ORIGINAL

E000009436

Court S. Rich - AZ Bar No. 021290
Eric A. Hill - AZ Bar No. 029890
Rose Law Group pc
7144 E. Stetson Drive, Suite 300
Scottsdale. Arizona 85251
Bus: (480) 505-3937
crich@roselawgroup.com
ehill@roselawgroup.com
Attorneys for the Solar Energy Industries Association

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB BURNS CHAIRMAN	BOYD DUNN COMMISSIONER	SANDRA KENNEDY COMMISSIONER
JUSTIN OLSON COMMISSIONER	LEA MÁRQUEZ PETERSON COMMISSIONER	

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	**DOCKET NO. E-01345A-19-0236** **SOLAR ENERGY INDUSTRIES ASSOCIATION'S DIRECT TESTIMONY OF KEVIN LUCAS**

Solar Energy Industries Association ("SEIA") hereby provides notice of filing the Direct Testimony (Rate Design) of Kevin Lucas in the above referenced matter.

RESPECTFULLY SUBMITTED this 9th day of October, 2020.

ROSE LAW GROUP pc

/s/ Court S. Rich
Court S. Rich
Eric A. Hill
Attorneys for Solar Energy Industries Association

ACC - Docket Control - Received 10/9/2020 10:56 AM
ACC - Docket Control - Docketed 10/9/2020 1:37 PM

Original e-filed and 8 copies hand delivered on this 9th day of October, 2020 with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

I hereby certify that I have this day served a copy of the foregoing document on all parties of record in this proceeding by regular or electronic mail to:

Robin Mitchell
Arizona Corporation Commission
legaldiv@azcc.gov
utildivservicebyemail@azcc.gov

Melissa Krueger
Pinnacle West Capitol Corporation
melissa.krueger@pinnaclewest.com
thomas.mumaw@pinnaclewest.com
theresa.dwyer@pinnaclewest.com
rodney.ross@aps.com
andrew.schroeder@aps.com
leland.snook@aps.com
ratecase@aps.com

Adam Stafford
Western Resource Advocates
stacy@westernresources.org
adam.stafford@westernresources.org
steve.michel@westernresources.org
autumn.johnson@westernresources.org

Timothy Hogan
ACLPI
thogan@aclpi.org
ezuckerman@swenergy.org
briana@votesolar.org
Sandy.bahr@sierraclub.org
louisa.eberle@sierraclub.org
janderson@aclpi.org
sbatten@aclpi.org
czwick@wildfireaz.org
cpotter@swenergy.org
miriam.raffel-smith@sierraclub.org
rose.monahan@sierraclub.org
brendon@gabelassociates.com

Greg Patterson
Munger Chadwick/Competitive Power Alliance
greg@azcpa.org

Richard Gayer
rgayer@cox.net

Patrick Black
Fennemore Craig, PC
pblack@fclaw.com
lferrigni@fclaw.com

Daniel Pozefsky
RUCO
dpozefsky@azruco.gov
procedural@azruco.gov
jfuentes@azruco.gov
rdelafuente@azruco.gov

Robert Miller
bob.miller@porascw.org
rdjscw@gmail.com

Kurt Boehm
Boehm, Kurtz & Lowry
kboehm@bkllawfirm.com
jkylercohn@bkllawfirm.com

Jason Moyes
Moyes Sellers & Hendricks
jasonmoyes@law-msh.com
jim@harcuvar.com
jjw@krsaline.com

Nicholas Enoch
Lubin & Enoch, PC
nick@lubinandenoch.com
bruce@lubinandenoch.com
clara@lubinandenoch.com

Patricia Madison
Patricia_57@q.com

Jonathan Jones
jones.2792@gmail.com

Karen White
Scott Kirk
Robert Friedman
Thomas Jernigan
Holly Buchanan
karen.white.13@us.af.mil
scott.kirk.2@us.af.mil
robert.friedman.5@us.af.mil
thomas.jernigan.3@us.af.mil
ebony.payton.ctr@us.af.mil
arnold.braxton@us.af.mil
holly.buchanan.1@us.af.mil

John Thornton
john@thorntonfinancial.org

Scott Wakefield
Hienton Curry, P.L.L.C.
swakefield@hclawgroup.com
stephen.chriss@walmart.com

Kimberly Dutcher
Navajo Nation Dept. of Justice
kdutcher@nndoj.org
aquinn@nndoj.org

Jason Mullis
Wood Smith Benning & Berman LLP
jmullis@wshblaw.com

Gregory Adams
greg.bass@calpinesolutions.com
greg@richardsonadams.com

Albert Acken
Dickinson Wright PLLC
aacken@dickinson-wright.com

Giancarlo Estrada
Kamper Estrada, LLP
gestrada@lawphx.com

Garry Hays
Law office of Garry Hays PC
ghays@lawgdh.com

Armando Nava
The Nava Law Firm PLLC
filings@navalawaz.com

John Coffman
John B. Coffman
John B. Coffman LLC
john@johncoffman.net

Thomas Harris
Distributed Energy Resource Association
thomas.harris@dera-az.org

Marta Darby
David Bender
Earthjustice
mdarby@earthjustice.org
dbender@earthjustice.org

Shelly Kaner
8831 W. Athens Street
Peoria, Arizona 85382

By: /s/ Hopi L. Slaughter

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	)))))))))))	**DOCKET NO. E-01345A-19-0236** **SEIA'S NOTICE OF DIRECT TESTIMONY OF KEVIN LUCAS**

DIRECT TESTIMONY

OF

KEVIN LUCAS

(RATE DESIGN)

ON BEHALF OF

Solar Energy Industries Association ("SEIA")

OCTOBER 9, 2020

Table of Contents

List of Tables and Figures

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. My name is Kevin Lucas. I am the Director of Rate Design at the Solar Energy Industries Association (SEIA). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.

A2. I began my employment at SEIA in April 2017 as the Director of Rate Design. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 20% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power. Founded in 1974, SEIA is a national trade association building a comprehensive vision for the Solar+ Decade through research, education and advocacy.

As Director of Rate Design, I have developed testimony in rate cases on rate design and cost allocation, in integrated resource plans on resource selection and portfolio analysis, worked on the New York Reforming the Energy Vision proceeding on rate design and distributed generation compensation mechanisms, and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy (Alliance) from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service providers that was seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters, and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University Of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, cum laude, from Princeton University in 1998.

Q3. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE ARIZONA CORPORATION COMMISSION?

A3. No, I have not.

Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?

A4. Yes. I have testified before the Maryland Public Service Commission in several rate cases and merger proceedings. Additionally, I have testified before the Maryland Public Service Commission in several rulemaking proceedings, technical conferences, and legislative-style panels, covering topics such as net metering, EmPOWER Maryland (Maryland's energy efficiency resource standard), and offshore wind regulation development.

I have also submitted testimony in rate cases and integrated resource plans before the Public Utility Commission of Texas, the Michigan Public Service Commission, the Public Utility Commission of Nevada, and the Colorado Public Utilities Commission. My complete CV is attached to my testimony.[1]

[1] Attachment KL-1, Kevin M. Lucas CV.

Q5. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A5. My testimony is provided on behalf of Intervenors, SEIA and the Arizona Solar Energy Industry Association (AriSEIA).

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A6. My testimony discusses aspects of Arizona Public Service's ("APS" or the "Company") filing related to cost of service and rate design for solar customers and customers combining solar with energy storage. I examine the Company's choices in developing its class cost of service study ("CCOSS") model that affect how solar customers are evaluated. I consider the CCOSS results against the Company's rates to determine whether solar customers are paying more or less of their cost of service compared to other customer classes.

I then analyze the Company's system and residential class load profiles to determine if the current on-peak periods are optimal. From there, I discuss modifications to the Resource Comparison Proxy ("RCP") tariff that will provide stability during a time of unprecedented policy uncertainty and analyze several APS policies that discriminate against solar customers and that hamper deployment of customer-sited solar and storage systems. I discuss the Company's non-residential rates and find several rate design issues that are unnecessarily holding back investment in solar and solar plus storage systems on medium- and large-sized businesses and not-for-profit customers. Finally, I propose a "Bring Your Own Device" program related to distributed energy resources.

Q7. PLEASE SUMMARIZE YOUR FINDINGS.

A7. I find the Company's CCOSS methodology does not conform with Commission requirements that it be "transparent, accessible, and flexible" and that it directly violates a Commission order related to the allocation of distribution costs. Further, the Company's use of site load (e.g. the load a customer would have absent solar) instead of delivered load (e.g. the load a customer actually incurs) in its CCOSS process incorrectly allocates costs to solar customers based on services that were not provided by the Company. When I make appropriate adjustments to the Company's CCOSS data, I find that the cost to serve and revenue recovery through non-frozen rates for solar customers is in line with similarly-sized non-solar customers.

In analyzing the Company's system and residential class load data, I find that the current definitions of summer and winter seasons are not supported. The summer months should be shifted to June through September, returning May and October to the non-summer season. Further, the on-peak and off-peak periods should be shifted one hour earlier, from 3 PM to 8 PM to 2 PM to 7 PM. Realigning the seasons and rates will send more appropriate price signals to customers to reduce demand during the months and hours when these reductions are actually useful.

I find that the RCP tariff should be frozen at its current 2019 Tranche level and that the lock-in period should be extended. These changes will provide needed stability to the solar industry that is still adapting to the RCP tariff. APS installations have not recovered to their pre-RCP levels, and data from Tucson Electric Power Company (which has a lower RCP value than APS) bodes poorly for installations under future RCP stepdowns. By locking in the RCP now, the Commission will help ensure that a vibrant solar industry will continue to provide economic and environmental benefits to all of APS's customers.

APS implements several policies that directly or indirectly discriminate against solar and that should be reconsidered. On the residential side, this includes limitations prohibiting customers with solar from taking service on any non-frozen rate. There is no reason to require a customer to choose between installing solar to provide some of their own electricity from clean renewable sources and taking service on the rate that best matches their lifestyle. Additionally, the Company's demand limiter, which restricts the demand charge that a customer may face, is only available for non-solar customers. There is no policy justification for this, and the Company produced no analytical evidence to support its position. Finally, the Grid Access Charge ("GAC") is neither cost based nor necessary to ensure sufficient cost recovery from solar customers on the R-TOU-E rate and should be eliminated.

Both residential and non-residential customers face solar system size limitations. The residential sizes are generally acceptable but should be revised to be based on the inverter capacity of a system rather than the solar panel nameplate capacity as the inverter capacity is the proper measure of interconnected capacity. The non-residential system size limit should be increased to allow customers to better size their system to meet their annual energy usage and help meet sustainability goals.

The Company's primary non-residential E-32 tariffs contain rate design choices that cause problems for both solar and non-solar customers. There is a distinct disincentive for high load factor customers to downsize from a "larger" tariff to a "smaller" one, such as moving from E-32 L to E-32 M. Additionally, the declining block structure and demand ratchet on some of the E-32 rates do not encourage demand reduction. This is clearly contrary to the Company's goals to reduce peak demand and creates perverse incentives for non-residential customers. Further, the Company's non-residential storage pilot program approved in the last rate case, has failed to spur the adoption of any storage, as reflected by the fact that zero customers take service on this tariff. I discuss several changes that can improve this tariff and enable it to meet is policy objectives.

Finally, I provide some thoughts on Commissioner Peterson's request for information related to Bring Your Own Device programs. I recommend a tariff-based structure that primarily utilizes service aggregators to coordinate and manage distributed energy resources to meet grid service needs. This tariff can provide distribution capacity deferral and increase demand flexibility to manage challenging real-time grid conditions, all while reducing costs to both participants and non-participants.

Q8. PLEASE LIST YOUR SPECIFIC RECOMMENDATIONS FOR THIS CASE.

A8. I make the following recommendations in my testimony. Collectively, these changes will recognize that solar customers provide benefits to the system and reasonably contribute to revenue adequacy. The modifications to the CCOSS method will help meet the Commission's requirements to be "transparent, accessible, and flexible." The rate design modifications will better align price signals with load conditions on the grid and provide new opportunities for residential and non-residential customers to manage their load to the benefit of all customers. The policy recommendations will remove barriers to solar deployment and can help maintain the vibrance of an industry contributing to economic development in APS's territory.

CCOSS recommendations

- Utilize more modern cost allocation approaches such as those recommended by the RAP Manual that are better suited to the operation of modern utilities.
- Provide more detail in how load shapes are calculated from billing information, including more information about demand and energy adjustments.
- Recombine solar customers with non-solar customers in the CCOSS and rate design process.
- Use delivered energy rather than site energy for solar customers.
- Remove the "solar credit" concept from the CCOSS.
- Properly adhere to the Commission's requirement that the CCOSS workpapers be transparent, accessible, and flexible as directed in Decision 75859.
- Properly adhere to the Commission's requirement that residential subclass Class NCP values are calculated based on the same hour as the combined total residential Class NCP as directed in Decision 76900.
- Develop a more robust method to account for customer growth over the test year in the CCOSS.
- Investigate ways to reduce metering costs for solar customers.

Rate Design Recommendations

- Refile R-2, R-3, and R-TOU-E tariffs with a 2 PM to 7 PM on-peak period from June to September.
- Redesign R-TECH tariff as a volumetric TOU rate.
- Remove the declining block structure for both energy and demand rates on the E-32 rates
- Remove the demand ratchet from the E-32 L tariff
- Reduce the demand charge on the E-32 S tariff to $8.805 / kW to reduce the balance of revenue recovery through demand charges to be in between the E-32 XSD and E-32 M tariffs
- Better align the "edges" between tariffs to prevent large rate shocks and disincentives for high load factor customers to reduce their demand

- Make several changes to the storage pilot guidelines that led to the E-32 L SP tariff
  - Eliminate the 20% peak demand reduction
  - Reduce the on-peak period to 4 hours
  - Create a reasonable differential between the on-peak and remaining hour demand rate
  - Increase the differential in the energy rates
  - Allow sufficient time for storage systems to be fully charged by solar

General Policy Recommendations

- Allow customers to install solar on any active residential tariff.
- Eliminate the GAC.
- Extend the demand limiter to solar customers on the R-2 and R-3 rates.
- Adopt TEP definition of connected load as the maximum demand divided by 0.6, and after multiplying this value by 125%, apply it to the AC inverter rating. Change the system size limits for residential customers to 15 kW_{AC}, 30 kW_{AC}, 45 kW_{AC}, and 60 kW_{AC} for 200-amp, 400-amp, 600-amp, and 800-amp service, respectively.
- Freeze the RCP stepdown at the 2019 Tranche level.
- Extend the duration of the RCP price lock to 18 years.

BYOD Program Recommendations

- Use a tariff-based mechanism to compensate customers with existing and new DERs and provide payments to aggregators for coordinating distribution services.
- Structure a two-tiered payment system that will provide some upfront deployment incentive for customers as well as payments to aggregators for value provided.
- Set total compensation at a level below the avoided cost of the traditional utility upgrade or service to ensure all ratepayers realize savings.

II. APS'S CLASS COST OF SERVICE STUDY METHODOLOGY IS OPAQUE, NEEDLESSLY COMPLEX, VIOLATES A COMMISSION ORDER, AND SYSTEMATICALLY OVER-ALLOCATES COSTS TO SOLAR AND RESIDENTIAL CUSTOMERS

Q9. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A9. In this section, I discuss the Company's CCOSS methodology. I begin by tracing the mechanics of the process by following data from load studies to the allocator development workpaper and finally into the CCOSS model itself. I find a number of errors and questionable assumptions in each step of this process, including the Company's decision to directly disregard the Commission's order on a particular element of the CCOSS design. I conclude with a critique of the "solar credit" methodology in the CCOSS and present an alternative CCOSS that correctly allocates costs based on the underlying load the Company serves.

Q10. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A10. The approach that APS uses for solar customers in its CCOSS methodology is based on the fundamentally flawed premise that the Company serves load that it does not actually serve. APS argues that it is responsible for the "site" energy of a solar customer – the total load that would be present if the customer did not have solar – rather than the "delivered" energy of a solar customer – the actual kW and kWh that the Company delivers to the solar customer. Try as it may to argue to the contrary, the Company cannot dismiss the reality that solar customers have solar PV systems that serve some of their load; it is simply a matter of physics that the Company does not serve customer load in excess of the instantaneous demand net of their solar generation.

APS carries this flawed notion of site energy into the load studies that provide the basis for the Company's CCOSS allocators. This, combined with the choice to model nine separate residential subclasses, results in CCOSS allocators for both solar and non-solar residential customers that are larger than they should be. When carried into the CCOSS, this results in an over-allocation of costs to the residential class relative to non-residential customers.

The Company's workpapers contain several other errors as data moves from the load studies to the CCOSS model. Primary among them is the disregarding of an explicit Commission directive from the most recent UNS Electric Inc's rate case that utilities calculate each residential subclass NCP based on the same hour as the residential class NCP.[2] The Company fails to do this, resulting in residential subclasses being overallocated distribution costs. APS also used the wrong metering costs for solar customers, had the wrong customer counts for some subclasses, and did not account in the CCOSS for the sizable customer growth and shrinkage of its numerous residential subclasses.

The Company's CCOSS workpapers are full of unlinked files, hardcoded values, and inscrutable formulas. Despite an order from the Commission to increase the transparency of its CCOSS and allow intervenors to manipulate the model to produce alternative results, I had to spend considerable effort to reverse engineer APS's various workpapers before being able to produce my own analysis. This effort was complicated by the Company's refusal to provide access to files that were directly imported into the CCOSS, requiring one to take critical figures such as revenue from retail rates on faith.

While APS's CCOSS in the current case may be an improvement over previous cases, it still does not comport with Commission requirements for transparency, accessibility, and flexibility. I conclude with several recommendations that will produce a more robust CCOSS in this and future cases for APS and other Arizona utilities.

An Overview of APS's Class Cost of Service Study Methodology

Q11. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF HOW A CCOSS WORKS.

A11. The CCOSS is an analytical model that is used to map a utility's costs onto the ultimate customers who are responsible for causing those costs. This concept of "cost-causation" is

[2] Decision 76900, Docket E-04204A-15-0142 at 83-84.

central to cost-of-service regulation. The CCOSS has three primary steps: functionalization, classification, and allocation.

Q12. PLEASE DESCRIBE THE FUNCTIONALIZATION STEP.

A12. The functionalization step parses all of a utility's assets and expenses and assigns them to the core function that they serve. Power plants generate power and provide energy; assets and expenses related to the generation of power are functionalized as "Production." Transmission lines and high-voltage substations primarily exist to transmit power from generating stations to the distribution facility. These assets and expenses are functionalized as "Transmission." The poles, wires, and substations of the distribution system are designed to deliver power from the transmission system to the end customer. These assets and expenses are functionalized as "Distribution." Finally, expenses and assets related to serving customers such as customer service and billing systems are functionalized as "Customer."

Q13. PLEASE DESCRIBE THE CLASSIFICATION STEP.

A13. Once the Company's assets and expenses are broken down by their core function, they are further divided by classification. Classification typically involves three categories: demand, energy, and customer. Demand costs vary with the amount of demand, measured in kW, that customers put on the system. For instance, peaking power plants primarily exist to provide capacity during high-load hours, and thus these assets would be classified by the Company as demand. By contrast, energy expenses vary based on the total quantity of energy, measured in kWh, that is produced. The fuel and variable operations and maintenance ("O&M") associated with generating energy from power plants is classified as an energy-related cost. Finally, costs that do not vary based on either demand or energy are classified as customer-related costs. Examples here include customer meters.

Q14. PLEASE DESCRIBE THE ALLOCATION STEP.

A14. At this point, the Company's assets and expenses have been broken down by primary function and further classified based on demand, energy, and customer categories. The final step is to allocate these costs to different customer classes. A CCOSS will typically at a minimum separate residential, small commercial, large commercial, and industrial customers into their own cost of service class. This is necessary as not all customers use all elements of a utility's grid. For example, industrial customers typically do not use the low-voltage distribution system; thus, it would be inappropriate to allocate costs for the low-voltage distribution system to industrial customers.

The allocation between the cost of service classes is done based on cost allocators. These allocators are calculated based on load characteristics such as demand coincident with the system peak, demand independent of the system peak, total energy use, total on-peak energy usage, total customer count, and so on. Classified costs are allocated based on corresponding allocators. Fuel and variable O&M energy costs will be spread across the cost of service classes based on the share of total energy that each class consumes. Similarly, power plant demand costs will be allocated based on a measure of the fraction of peak system demand that each class is responsible for.

Q15. PLEASE PROVIDE AN EXAMPLE OF HOW ALLOCATORS ARE USED IN THE CCOSS.

A15. Supposed that one is determining how to allocate costs for distribution substations. The Company classifies these assets and expenses as demand-related costs and allocates them based on the "DEMDIST1 NCP Demand @ Substation Level w/losses (KW)" allocator.[3] This allocator is based on the retail class demand grossed up for substation line losses of 2.775%. In the Company's workpaper, the "Legacy Solar (Energy)" class (one of the nine residential classes the Company uses in the CCOSS) has a value for NCP demand @ Substation Level of 435,328 kW. The total DEMDIST1 value for all customer classes is 7,269,621 kW. Thus, the Legacy Solar (Energy) class represents 5.99% of the total for this allocator. If one were allocating $100 million in distribution substation costs, then the Legacy Solar (Energy) class would be allocated 5.99% * 100 million = $5.99 million for this asset class.

[3] LRS_WP4DR TY Development of Allocation Factors Report, tab "Schedule G-7"

Q16. AFTER THESE THREE STEPS, WHAT HAPPENS NEXT IN THE CCOSS?

A16. Once all of the costs have been functionalized, classified, and allocated, the CCOSS calculates the revenue requirement for each class that is required to recover expenses (including taxes on income) and earn a return on and of the capital assets that the class utilizes. This class-specific revenue requirement can then be used as an input into the rate design process.

Q17. DOES APS FOLLOW THE GENERAL METHOD YOU DESCRIBED ABOVE?

A17. It does for the most part. The Company's functionalization of costs follows a traditional approach. Production assets such as power plant and land are classified as demand-related costs, as are transmission and distribution assets. Meters and customer service are classified as customer-related costs. The Company matches the cost allocator based on the voltage level (and thus line losses) to the asset being allocated. For instance, distribution substation costs are allocated based on the share of demand that includes losses up to the substation, while overhead transformers are allocated based on the share of demand that includes losses up to the transformer.

Q18. ARE THERE AREAS WHERE APS DIVERGES FROM THE TRADITIONAL METHOD YOU DESCRIBE?

A18. Yes. As I discuss later, the Company diverges in two substantive ways. First, it produced a total of nine residential subclasses that largely mirror retail rate classes. Second, it allocates costs to residential solar customers based on "site" load rather than "delivered" load.

Q19. IS THE TRADITIONAL APPROACH DISCUSSED ABOVE THE MOST APPROPRIATE FOR A MODERN UTILITY SUCH AS APS THAT HAS AN EVOLVING MIX OF PRODUCTION ASSETS, INCREASING DISTRIBUTED GENERATION, AND ADVANCED METERING AND DATA MANAGEMENT CAPABILITIES?

A19. No. Many utilities still operate under cost of service and rate design conventions that emerged in a different era, and unfortunately, are becoming less and less relevant to a modern energy landscape. Much of the established thinking around cost allocation and rate design stem from several seminal documents listed below:

- *Principles of Public Utility Rates* by James C. Bonbright (first edition, 1961; second edition, 1988).
- *Public Utility Economics* by Paul J. Garfield and Wallace F. Lovejoy (1964).
- *The Economics of Regulation: Principles and Institutions* by Alfred E. Kahn (first edition Volume 1, 1970, and Volume 2, 1971; second edition, 1988).
- *The Regulation of Public Utilities* by Charles F. Phillips (1984).
- The 1992 NARUC *Electric Utility Cost Allocation Manual*.[4]

Common among these documents is their age. The most recent is nearly thirty years old, and Bonbright's formative work is approaching sixty years in age. All were developed in an era of large, centralized power plants operating in vertically integrated markets. Distributed resources as we think of them today largely did not exist. Renewable generation was primarily limited to large hydro projects, and the notion that wind and solar could cost-effectively provide substantial fractions of a utility's energy and capacity needs was simply not considered.

Q20. WHAT GUIDANCE IS AVAILABLE FOR UTILITIES AND COMMISSIONS AS THEY WORK THROUGH THESE ISSUES IN A MODERN CONTEXT?

A20. A new manual on cost allocation and rate design was recently published by the Regulatory Assistance Project ("RAP"). This document, *Electric Cost Allocation for a New Era: A Manual* ("RAP Manual") is the product of three leaders in the utility regulatory industry, Jim Lazar, Paul Chernick, and William Marcus. Together, the authors have over 120 years of collective experience and have participated in hundreds of regulatory proceedings throughout the world.[5] Their manual updates traditional cost allocation and rate design approaches based on the emerging energy landscape where utilities have access to detailed advanced metering

[4] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). Electric cost allocation for a new era: A manual. Montpelier, VT: Regulatory Assistance Project. ("RAP Manual"). Available at https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf

[5] RAP Manual at 9.

infrastructure ("AMI") data, can substitute renewable energy for fossil operating expenses, and must incorporate increasing demands for flexibility from its customers.

Q21. WHAT INFORMATION IS IN THIS DOCUMENT THAT MIGHT BE USEFUL TO THE COMMISSION AND INTERVENORS IN THIS AND FUTURE PROCEEDINGS?

A21. I strongly recommend that all parties working in this and future rate cases review this document. It previews some of the tensions that APS may soon find itself grappling with as it shifts from a more conventional generation mix to one based on renewable energy and demand-side management.

For instance, the RAP Manual covers the allocation of renewable generation and smart meters in a modern context. Rather than simply allocating renewable generation costs to production, as may have been done traditionally with generating assets, utilities should recognize that renewable facilities are increasingly a substitute for fuel and variable O&M costs from traditional generators. Likewise, AMI offers many more services than simple customer billing. AMI provides the Company with valuable information related to the real-time status of its grid, is a conduit for demand response programs, and provides insights to customer usage. If the Company defaults cost allocation to the traditional metering function and does not recognize the multiple benefits to demand and energy that AMI provides, these costs will be misplaced.[6]

APS Inappropriately Allocates Solar Customer Costs Based on Demand It Does Not Serve

Q22. PLEASE DESCRIBE THE WORKPAPERS THAT THE COMPANY USES TO DEVELOP THE INPUTS TO THE CCOSS.

A22. The Company's methodology begins with customer billing data from the test year (July 2018 to July 2019). Approximately 750,000 of the roughly 1.1 million residential customers who have complete AMI billing data are included in the load research census. An average load shape is calculated for each subclass based on customers with complete data, which is then

[6] RAP Manual at 18.

grossed up to represent the total number of customers in that subclass. The specific load shape is further adjusted to normalize monthly peaks with the overall system peaks. However, this last step is only performed for delivered load (used for non-solar customer groupings), and not for site load (used for solar customer groupings).[7]

Based on these average load shapes, APS produced 103 different load research reports ("LRR") containing key data such as coincident peak, non-coincident peak, energy usage, and customer count.[8] Some of the LRRs combine customer groupings. For instance, there is an LRR for "Demand Rate No Solar", which presents data for the combination of all customers in the "R-2 No Solar", "R-3 No Solar", and "R-TECH No Solar".[9]

Data for solar customers is presented in three ways: site, delivered, and produced. The site LRR represents load served by both the Company and the PV customer's solar system. The delivered LRR represents load only served by the Company. The produced LRR represented solar production independent of customer load.

Q23. HOW DOES THE COMPANY USE THE LRRS?

A23. The LRRs are used as inputs into the Company's "Development of Allocation Factors Report" workpaper ("Allocator WP").[10] Nine different residential subclasses are mapped from the LRR to the Allocator WP. For non-solar customers, the Company-provided LRR data (i.e. delivered energy) is used. For solar customers, the Company instead uses the corresponding site LRR. Table 1 below shows nine subclasses that the Company uses in the LRRs and CCOSS, along with the retail rates they represent.

[7] Attachment KL-2, SEIA 21.2.

[8] Each LRR contain the following data by month: SUMMATION IND MAX (MW): Non-Timed, On-Peak, Off-Peak. CLASS PEAK (MW): On-Peak, On-Peak Date & Time, Off-Peak, Off-Peak Date & Time. ADJUSTED COINCIDENT (MW): System, Time (Hr Ending). ENERGY (MWH): On-Peak, On-Peak %, Off-Peak, Off-Peak %, Total. CUSTOMERS: Monthly Count. FACTORS: Coincident Factor (CP), Load Factor (Max) %, Load Factor (NCP) %, Load Factor (CP) %. CUSTOMER AVERAGES: Energy Use (kWh), Ind. Max Demand (kW), Coincident Demand (kW), NonCoincident Peak Demand (kW)

[9] Attachment KL-3, SEIA 4.1c

[10] LRS_WP4DR TY Development of Allocation Factors Report.xlsx

LRR Class	CCOSS Class	Tariff ID	Retail Rates
Legacy Energy Rate Solar Site	Legacy Solar (Energy)	E-12, ET-1, and ET-2	E-12, ET-1, and ET-2 with Solar
ECT Solar Site	Legacy Solar (Demand)	ETC-1R and ETC-2	ETC-1R and ETC-2 with Solar
R-TOU-E Solar Site	R-Solar (TOU)	TOU-E	Saver Choice - TOU with Solar
New Demand Rate Solar Site	R-Solar (Demand)	R-2, R-3, R-Tech	Saver Choice Plus, Saver Choice Max, Saver Choice Tech with Solar
R-XS	R-BASIC (0-600 kW)	R-XS	Lite Choice – No Solar
R-Basic	R-BASIC (601-999 kW)	R-Basic	Premier Choice – No Solar
R-Basic LRG	R-BASIC (1000+ kW)	R-Basic Large	Premier Choice Large – No Solar
R-TOU-E No Solar	R-TOU	TOU-E	Saver Choice TOU – No Solar
Demand Rate No Solar	R-DEMAND	R-2, R-3, R-Tech	Saver Choice Plus, Saver Choice Max, Saver Choice Tech – No Solar

Table 1 - LRR, CCOSS, and Retail Rate Mapping

Q24. WHAT IS THE RELATIVE SIZE OF THESE CUSTOMER GROUPS?

A24. Table 2 shows the number of customers and total energy usage for each LRR class. Although there is a substantial amount of testimony from the Company related to solar customers and their impact on its system and finances, the fact is that as of the end of the test year in June 2019, solar customers represented only 7% of all residential customers and only 8.1% of all delivered energy. To reduce confusion, I have renamed some of the LRR classes below.

LRR Class	Customer Count	Delivered Energy	% of Customers	% of Delivered Energy
Legacy Solar – Energy	72,221	801,035	5.9%	6.5%
Legacy Solar – Demand	3,488	56,297	0.4%	0.3%
New Solar – Energy	11,382	64,133	0.5%	1.0%
New Solar – Demand	3,826	23,859	0.2%	0.3%
R-XS	264,712	1,401,134	20.4%	30.3%
R-Basic	117,844	1,217,930	10.6%	9.0%
R-Basic LRG	37,733	777,655	23.7%	10.4%
R-TOU No Solar	377,493	5,058,310	3.4%	5.8%
R-Demand No Solar	227,839	4,088,516	33.8%	37.5%
All Solar	90,917	945,324	7.0%	8.1%
All Non-Solar	1,025,621	12,543,544	93.0%	91.9%

Table 2 - LRR Class Customer and Delivered Energy

Q25. DID THE COMPANY USE DELIVERED LOAD OR SITE LOAD FROM THE LRRS IN ITS CCOSS?

A25. APS did not use delivered energy data for residential solar customers, instead opting for site energy data. In doing so, it introduces into the CCOSS a violation of a fundamental principle that customers should be able to take any action – as long as it is safe and legal – to alter the amount of energy and power they purchase from APS. Customers can choose (or not choose) to install energy efficient appliances, install gas appliances, participate in demand response programs, install energy storage systems, or install rooftop PV systems. As long as these actions occur behind the meter and are interconnected and operated in accordance with the Company's and the state's regulations, that should be the end of the matter. Essentially, what happens behind the meter should stay behind the meter.

The absurdity of using site load can be easily illustrated. Reaching behind the meter and allocating DG customer costs based on total site load (regardless of whether a portion of the load is met by self-generation) is equivalent to allocating costs to a customer for the energy they *would have* consumed from the utility had they not installed energy-efficient windows; or the energy they *would have* consumed had their kids not gone off to college; or the energy they *would have* consumed if they were year-round, rather than seasonal, residents. When a customer chooses to install new technology or undergoes a lifestyle change that affects their energy consumption, the services they require of their utility change. As a result, that customer's cost-causing usage patterns change. However, it would be inappropriate to continue to charge them based on their past usage patterns, or upon their potential future usage patterns. Rather, customers should be charged based on their actual usage, which is measured by their delivered load.

Q26. HAS THE COMMISSION OPINED ON THIS MATTER?

A26. Yes. In Docket No. E-0000J-14-0023, the Commission issued Decision 75859 that discussed a variety of issues related to solar. In that proceeding, intervenors Vote Solar and Staff argued that customers should be allowed to do what they want behind the meter:

> Vote Solar agrees that self-use of rooftop solar provides significant benefits, but believes focusing on exports is the better approach because the utility should not "look behind the meter" based on a customer's technology choices. Vote Solar strongly believes in a customer's right to self-consume energy generated behind the meter through its own investment.
>
> Like Vote Solar, Staff believes that what a customer chooses to do behind the meter regarding its energy needs is the customer's concern, and that the customer's right to reduce its load by the installation of a DG meter is no different from the customer's right to reduce load by conservation, insulation, high efficiency appliances, or storage. In addition, Staff states that it views the export rate more in the nature of a wholesale rate, and not a retail rate, which would apply to self-consumption.[11]

Ultimately, the Commission agreed with the logic of Vote Solar and Staff, concluding:

> For the reasons voiced by Vote Solar and Staff the methodology we adopt will be used for the purpose of ascertaining the appropriate level of compensation to be paid to rooftop solar customers for their exported energy, and not for the purpose of determining a monetary value of the energy a DG customer consumes on site.[12]

While this particular point was related to the compensation for DG production, the notion that the Company should not look behind the meter remains true whether discussing load reductions, valuing solar generation, or using site or delivered load in the CCOSS. Site load necessarily requires one to look behind the meter and is in direct conflict with the Commission's conclusion.

---

[11] Docket No. E-0000J-14-0023, Commission Decision 75859 at 147.
[12] Docket No. E-0000J-14-0023, Commission Decision 75859 at 147.

Q27. HAS THE COMMISSION RULED ON THE APPROPRIATENESS OF USING SITE OR DELIVERED LOAD FOR SOLAR CUSTOMERS?

A27. No. When asked whether the Commission explicitly ruled on the appropriateness of using site or delivered energy when establishing cost allocators for residential solar customers, the Company initially responded:

> The Arizona Corporation Commission has ruled that residential rooftop solar customers are different than other residential customers from a cost perspective because they are partial requirements customers that export power to the grid. Therefore, they should be treated as a separate class in a cost-of-service study. However, the Commission left the cost allocation methods to be determined in the specific utility rate cases. See Decision No. 75859 in Docket E-00000J-14-0023. The method used by the Company in this proceeding is the same method used in the sited docket and in the prior APS rate case."[13]

In a follow up, the Company continued:

> The Commission explicitly recognized in Decision No. 75859, in the Value and Cost of Distributed Generation proceeding, that the cost to serve solar customers is different than non-solar customers because they are partial requirements customers that export power to the grid. This means that the cost-of-service study must recognize and estimate these differences. Therefore, to base the cost study strictly on delivered load, which is the identical method for allocating costs to non-solar customers, would be incorrect, because it would not recognize these cost differences.
>
> The Commission did not determine the precise method to be used in recognizing these cost differences – it left that up to each utility in their rate case filings. However, two fundamental approaches would be to either (1) base the initial cost allocation on site load and then credit back the cost savings attributable to the solar generation or (2) base the initial cost allocation on delivered load and then add the additional costs needed to serve solar customer.[14]

Q28. WHAT DOES THE COMMISSION'S ACTUAL ORDER STATE?

A28. The Commission's order in Decision No. 75859 states the following:

> We agree with APS that the appropriate test for the formation of a subclass of customers **for purposes of rate design** is whether a sub-group of customers is sufficiently different from the sub-group's current classification in regard to service, load, or cost characteristics to place that sub-group into a separate class. The record in this proceeding demonstrates that rooftop solar customers are partial requirements customers who export power to the grid, and we therefore find that rooftop solar customers are a separate class of customers. The ratemaking implications of this

[13] Attachment KL-4, SEIA 4.2h.
[14] Attachment KL-5, SEIA 9.4.

> separate class treatment are to be determined in each utility's rate case supported by a fully vetted cost of service analysis.[15]

Notably, the Commission's order constrains the designation of solar customers as a separate class "for the purposes of rate design." Rate design is a separate process from calculating the cost of service, and the Company correctly uses delivered billing determinants in the calculation of its rates. Contrary to the Company's claim, there is no explicit directive from the Commission that solar customers must be placed into a separate subclass within the CCOSS or for the differences between site and delivered energy to be analyzed.

Q29. AS A FUNDAMENTAL QUESTION, DO YOU BELIEVE THAT SOLAR CUSTOMERS SHOULD BE TREATED SEPARATELY IN EITHER THE CCOSS OR FOR THE PURPOSES OF RATE DESIGN?

A29. No, I do not. The primary arguments that parties use to advocate for the separation of solar customers into their own class is based on an analysis of load characteristics and a claim that solar customers exhibit far too much variation from "normal" customers to be grouped together. However, there is no single "normal" residential customer, and substantial variation exists among many types of customers that historically have been grouped together in the CCOSS and in rate design.

For example, residential customers who live in apartments have a different cost profile than customer living in detached single family homes. Rural and urban customers impose different costs on the system. Customers with electric heating have different load profiles from those with gas heating, and customer with pools have a high-load motor that is not present for customers without pools. Each of these customer groups could potentially be a subclass of customers for either CCOSS or rate design purposes as their loads and use of the system varies widely. However, the Company correctly does not break each of these customers out into their own class but allows a reasonable degree of variation to exist within its classes.

[15] Docket No. E-0000J-14-0023, Commission Decision 75859 at 146. (emphasis added)

The variation in the key load characteristics of solar customers falls within the range of the variation of other types of customers. Vote Solar witness Briana Kobor provided such an analysis in a previous case, using APS's own data.

> There are several distinct groups of customers larger than the group of rooftop solar customers with highly varying load shapes that could have potential implications for cost recovery, yet it is only solar customers who APS has chosen to isolate for analysis in its COSS and it is only solar customers APS singles out for proposed differential rate treatment.[16]

The Commission should recognize this fact and direct the Company to regroup solar customers with other residential customers in both the CCOSS and the rate design process.

Q30. DOES THE COMPANY ALREADY TREAT SOLAR CUSTOMERS DIFFERENTLY IN ITS TARIFFS?

A30. Yes. The Company has frozen a number of legacy tariffs that previously served solar customers. New solar customers cannot sign up for the R-Basic or R-XS tariffs, and must take service on either the volumetric R-TOU-E tariff or the demand tariffs R-2, R-3, and R-TECH. Solar customers who take service on the R-TOU-E tariff must also pay a grid access charge ("GAC") that is not applicable to non-solar customers. These actions effectively treat solar customers as a separate class of customers from non-solar customers.

Q31. WHAT IS YOUR VIEW ON THE TWO "FUNDAMENTAL" APPROACHES THAT APS SUGGEST MUST BE USED TO HANDLE SOLAR CUSTOMERS IN THE CCOSS?

A31. The Company has chosen the first method of using site load and crediting back cost savings attributable to solar generation. I discuss several issues with this approach below. The second method – using delivered load and adding in additional costs needed to serve the solar customer – would require the Company to identify, quantify, and justify any additional costs beyond those required to serve the delivered load.

Q32. HAS THE COMPANY IDENTIFIED POTENTIAL COSTS ASSOCIATED WITH SERVING SOLAR CUSTOMERS THAT EXCEED THE COST OF SERVING ITS DELIVERED LOAD?

A32. The Company claims to have done so. It stated that using site energy is necessary to

[16] Direct Testimony of Briana Kobor on behalf of Vote Solar, Docket No. E-01345A-16-0036

> capture[] the cost of providing grid services for the rooftop solar customer's export of energy and backup of the customer's self-supplied generation, including support for the starting of motors (e.g. the in-rush current associated with the starting of an air conditioning unit, which generally cannot be met by a solar array)."[17]

It elaborated that

> solar customers in areas with high solar adoption have the potential to cause high voltage during the Spring and Fall months. APS has an obligation to maintain voltage, and installing or upgrading traditional equipment such as reconductoring, feeder additions, transformer upgrades, capacitor banks and voltage regulators are some options available to APS.[18]

Q33. HAS THE COMPANY QUANTIFIED ANY OF THESE SUPPOSED "GRID SERVICES" COSTS?

A33. No. When asked where in the CCOSS customers are charged for "in-rush current", APS responded: "This is not a specific allocated amount. However, the costs would generally be included in the demand-related components for the generating plants and the grid."[19] When asked where in the CCOSS customers were charged for costs related to maintaining distribution voltage within the required operating limits, it again responded "This is not a specific category, but rather included in distribution primary and substation costs."[20]

Q34. HAS THE COMPANY DOCUMENTED INSTANCES WHEN IT HAD TO RECONDUCTOR LINES, ADD FEEDERS, OR UPGRADE OR INSTALL TRANSFORMERS, CAPACITOR BANKS, AND VOLTAGE REGULATORS TO ACCOMMODATE SOLAR CUSTOMERS?

A34. APS indicated that it "does not track costs in a way that allows it to determine whether or not specific upgrades and additions were caused by installing solar."[21] It further indicated it has not added new feeders, new capacitor banks, or new voltage regulators, and has not reconductored lines to accommodate residential PV customers.[22]

Q35. WHAT IS THE IMPLICATION OF THIS?

A35. The Company admits that is has no cost information related to the supposed cost of providing grid services for rooftop solar customers that is incremental to providing them with basic

---

[17] Attachment KL-6, SEIA 2.6b.
[18] Attachment KL-7, SEIA 7.12h.
[19] Attachment KL-8, SEIA 7.12e.
[20] Attachment KL-7, SEIA 7.12h.
[21] Attachment KL-9, SEIA 11.9.
[22] Attachment KL-10, SEIA 22.1.

electrical service. Further, it admits that these grid services are simply part of the generating and distribution systems that provide power and energy to customers. Put simply, the cost of serving the load of solar customers is already reflected in the cost of the generation, transmission, and distribution assets that serve the actual, delivered load of any customer, solar or not.

If the Company has not incurred or quantified costs for residential customers beyond those required for delivered load, and it characterizes "grid services" costs as already part of demand-related generation and distribution services, then it follows that a CCOSS based on delivered load without modification appropriately captures the costs and grid services needed to serve solar customers.

Q36. WHY IS THE COMPANY SO RELUCTANT TO ADMIT THAT IT IS ONLY RESPONSIBLE FOR SERVING THE DELIVERED LOAD OF A CUSTOMER?

A36. I am unclear. The Company was evasive in its responses when pressed further on this issue. When asked whether it served the site or delivered load of a solar customer, the Company responded: "The company serves the site load for generation capacity and grid capacity costs, with an offset for the solar capacity contribution; the grid capacity cost necessary to facilitate the export solar power; the delivered energy costs, and the customer hook-up costs for the site load."[23] When provided an example of a customer with a site load of 10 kW and a PV system that is producing 4 kW, the Company was asked to confirm that it was in that moment serving 6 kW of demand. It declined to do so, suggesting that "generator capacity, transmission capacity, distribution primary and distribution secondary capacity necessary to serve the customer would be based on a much higher level of demand than the 6 kW of net load used in this example."[24]

[23] Attachment KL-11, SEIA 4.2f.
[24] Attachment KL-12, SEIA 9.3a.

Q37. THE COMPANY SUGGESTS THAT SOLAR CUSTOMERS ARE DIFFERENT FROM NON-SOLAR CUSTOMERS IN THAT IT HAS TO STANDBY TO PROVIDE SUFFICIENT POWER FOR THEIR ENTIRE SITE LOAD IF THE SOLAR SYSTEM FAILS. IS THIS ANY DIFFERENT FROM NON-SOLAR CUSTOMERS?

A37. No. The Company is responsible for serving the delivered load of all its customers. It plans its system based on an assumption of load diversity; that is, it does not assume that every customer will be maxing out their service drop capacity at the same time. In fact, the Company assumes that customers on a 200-amp service drop, which can theoretically pull 38.4 kW of power, only have a peak demand of 12.23 kW, less than 1/3 of their potential.[25]

A non-solar customer does not need to inform the Company that is has installed a new induction cooktop or electric vehicle charger, both of which can produce sizable increases in peak demand if activated along with other appliances. These customers are not allocated more costs in the CCOSS because of their potential to increase their demand over historic levels. If they choose to turn on their appliances in a manner that increases their peak demand, this will be accurately reflected in the Company's LRRs and CCOSS, and the customer class will be appropriately allocated more costs for this increase in usage.

Likewise, if a cloud covers a solar system during peak hours, the delivered load of the customer will increase and will be accurately reflected in the Company's LRRs. There is no justification to allocate costs on the hypothetical cost of serving the site load just as there is no justification for allocating EV owners more in case they decide to increase their on-peak usage. In both cases, the delivered load is the right value to use, properly capturing the customer's actual behavior that drives system costs.

[25] Attachment KL-13, SEIA 16.2a.

Q38. IS IT POSSIBLE THE COMPANY'S RESPONSES ARE CONFLATING THE ACTUAL SERVICE IT PROVIDES TO SOLAR CUSTOMERS WITH RESOURCE PLANNING CONCEPTS?

A38. It is possible. The insistence that the Company in actuality serves the entire site load – which if true would result in over-generation and frequency issues for the grid as a whole and massive power spikes for the individual solar customer – may be confused with resource planning concepts. The Company's claim that it must serve site energy is tantamount to assuming that every solar PV system will simultaneously fail during peak demand hours. Of course, solar PV does not output 100% of its power in 100% of the peak hours. But neither does it output 0% of its power in 100% of the peak hours.

The Company already plans for and actively manages the variability in solar output. In its IRPs, it calculates an assumed output of PV facilities during peak hours using an effective load carrying capacity ("ELCC") analysis or other approaches such as evaluating generation during the top 90 hours of system load. This is extended to both utility-scale PV operations and residential load forecasts.[26] In its operations, it can forecast near-term solar generation based on expected weather conditions and determine a more accurate solar generation figure than simply 0% or 100% of capacity. And in its LRRs, there is no need to adjust the historic data based on modeling; the delivered load captures exactly the balance of power between solar generation, self-consumption, and grid-supplied power.

Q39. AS A MATTER OF PHYSICS, DOES THE COMPANY PROVIDE 10 KW OF POWER TO A HOUSEHOLD THAT HAS A NET USAGE OF 6 KW?

A39. No. During normal grid conditions, and ignoring second order effects, the instantaneous power that a solar customer would draw from the grid will be the net of the instantaneous load from the house and instantaneous generation from the PV panel.[27] If the appliances are drawing 10 kW, and the PV system is providing 4 kW, the Company will provide the

---

[26] Attachment KL-14, SEIA 22.2.

[27] This example ignores issues related to power factors and voltage fluctuations, which are typically minor for individual residential customers.

remaining 6 kW. If the Company were somehow to send 10 kW to a household that was only consuming 6 kW of power, there would be massive electrical issues.

Q40. IS THIS CONSISTENT WITH HOW THE COMPANY'S POWER PLANTS AND GRID OPERATE?

A40. Yes. In a simple analogy, one can think of the power grid as a bathtub. Water flowing in through the bathtub faucet represents the supply of generated and purchased power. Water flowing down the drain represents the demand of customer load. The Company works to balance supply and demand of power and energy, maintaining the water at a constant level. If the drain is opened further, such as on hot summer days when air conditions are running, more water must flow from the faucet to maintain the level. If the drain is partially closed, such as at night or during mild months, the flow from the bathtub faucet must slow.

In this analogy, rooftop solar can be thought of as a hose that is connected to the bathroom sink. Solar produces power from a source other than the Company's power plants, just like the sink can add water to the bathtub that does not come from its faucet. Suppose the drain stays opened at a constant level. If the hose from the sink is turned on – representing generation from rooftop solar systems coming online – the Company must react and turn down the bathtub faucet to avoid increasing the level of the water. This is akin to the bathtub faucet serving the delivered load of a solar customer; part of their demand is being met from the hose from the sink, with only the balance needed from the Company. Under the Company's conceit that it serves a solar customers' site load, it does not turn down the bathtub faucet when the sink hose it turned on. If this were to happen, the water level would begin to rise, leading to an overflowing bathtub.

Q41. DO THE LRRS PROVIDE ANY INSIGHT ON WHETHER THE DEMAND FOR THE RESIDENTIAL CLASS IS REFLECTIVE OF SITE OR DELIVERED LOAD FOR SOLAR CUSTOMERS?

A41. Yes. There are separate LRRs for Total Residential, Residential No Solar, Residential Solar Site, and Residential Solar Delivered. As is expected, the Total Residential loads are equal to the sum of the Delivered Residential No Solar and Residential Solar load (3,977 MW = 3,669

MW + 308 MW), and are not equal to the sum of the Site Residential No Solar and Residential Solar load (3,977 ≠ 3,669 MW + 459 MW).[28]

Q42. DOES THE COMPANY'S LOAD FORECAST AND RESOURCE ADEQUACY PLANNING PROCESS PROVIDE ANY INSIGHT ON WHETHER DEMAND FOR THE RESIDENTIAL CLASS IS REFLECTIVE OF SITE OR DELIVERED LOAD FOR SOLAR CUSTOMERS?

A42. The Company stated that "site load is used for customers projected to adopt solar and delivered load is used for existing solar customers."[29] This doublespeak answer attempts to obscure the fact that customers who are "projected to adopt solar" are simply non-solar customers, and site load for non-solar customers is by definition equal to delivered load. The Company's obfuscation efforts notwithstanding, its load forecasts are entirely based on delivered load.

Q43. IF THE LRRS, THE RESOURCE ADEQUACY PLANNING PROCESS, THE RETAIL RATE DESIGN, AND THE ACTUAL OPERATION OF THE GRID ALL USE DELIVERED LOAD, WHAT IS YOUR RECOMMENDATION ON THE CCOSS?

A43. To be consistent with every other element of planning and operations, I recommend that the Commission require the Company to use the delivered load for solar customers in its CCOSS. If it is at a future date able to identify, quantify, and justify additional costs that are explicitly related to providing service to solar customers that is above any beyond the cost of providing their delivered power and energy, those costs could be included in the CCOSS.

The Company's Site Load / Solar Credit Process Creates Distortions in the CCOSS

Q44. HOW LARGE IS THE DIFFERENCE BETWEEN THE SITE AND DELIVERED LOAD IN THE COMPANY'S LRRS?

A44. Figure 1 below shows the relative size of the site load compared to delivered load in the key load metrics for each of the solar subclasses used in the CCOSS. The increase is starkest for

[28] Initial 1.31_ExcelAPS19RC00282_2018 2019 Load Research Report
[29] Attachment KL-14, SEIA 22.2.

the average and excess demand ("AED") and four coincident peak ("4CP") allocators, which are used to allocate production costs (AED) and transmission costs (4CP).[30] The site load exceeds the delivered load by 40-80% in the metrics that are used to allocate bulk power grid expenses, and by 15-30% in metrics that are used to allocate distribution-related expenses.

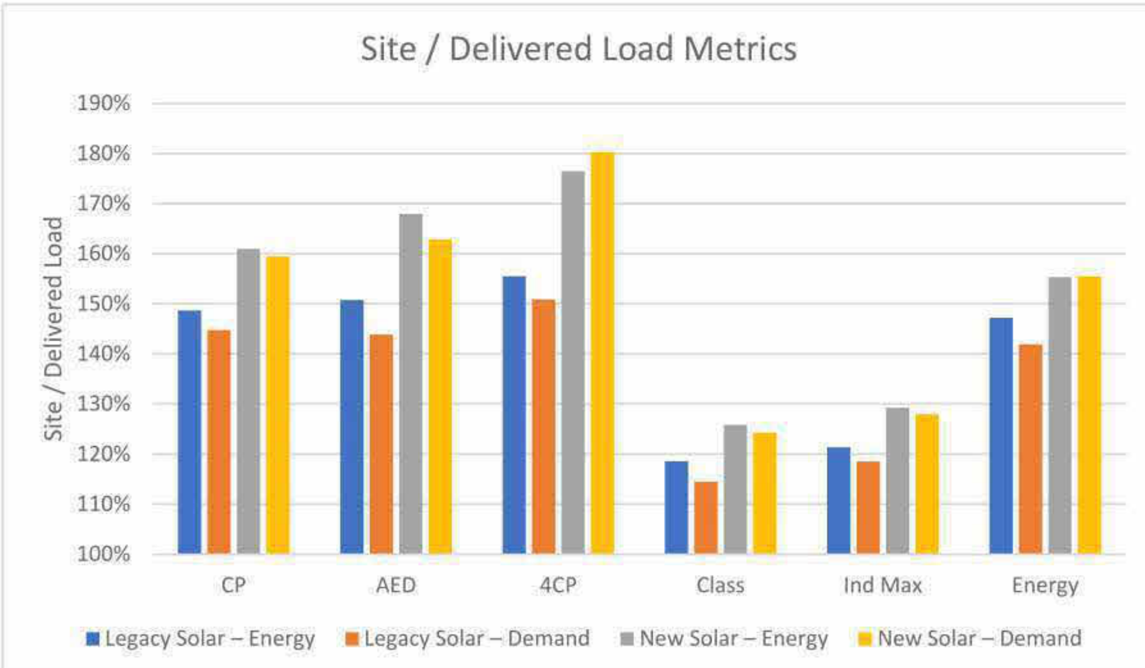


Figure 1 - Site / Delivered Load Metrics

Q45. WHAT IS THE IMPACT TO SOLAR CUSTOMERS OF USING SITE LOAD METRICS RATHER THAN DELIVERED LOAD METRICS IN THE CCOSS?

A45. Because costs are allocated to subclasses based on the subclasses share of the total allocator, using site load metric allocators for solar customers means that more costs are assigned to solar customers than would be under delivered load metric allocators. As seen from the data above, the increase in assigned costs can be quite high depending on the particular cost category.

[30] Production demand costs are allocated based on the "average and excess demand" allocator, which is a mathematical formula that uses the CP and Class NCP demand.

Q46. DOES THE COMPANY CLAIM THAT THEY ADJUST FOR THIS ISSUE?

A46. Yes. The Company claims that its "solar credit" mechanism in the CCOSS "fully credits residential solar customers for all cost savings resulting from the capacity (production, transmission, and distribution) and energy supplied to the grid by their rooftop solar systems."[31] I discuss issues with the solar credit in more detail below.

Q47. WHAT IS THE IMPACT TO ALL RESIDENTIAL CUSTOMERS OF USING SITE LOAD METRICS RATHER THAN DELIVERED LOAD METRICS FOR SOLAR CUSTOMERS?

A47. The residential class as a whole would be allocated more costs. Because the sum of the load metric of the nine residential subclasses are higher when using site instead of delivered, the share of the residential class's allocation increases. As an example, the sum of the energy at the generation level for the residential class using the solar site energy is 15,265,655 MWh out of a total energy usage of 31,279,384 MWh, making the residential class responsible for 48.80% of costs allocated based on energy. If the delivered values were used instead, the total residential class would be responsible for 14,772,530 MWh out of 30,786,259 MWh, or 47.98%. While the change of roughly 0.8% may seem small, the costs allocated in the CCOSS are zero-sum and massive.

Table 3 below shows the total residential contribution to key allocators using site energy instead of delivered energy. It also shows a rough mapping of the costs in the CCOSS that are allocated based on these figures.[32] As is shown below, using site energy results in the residential class as a whole being assigned over $20 million more than it would under the delivered energy allocators.

[31] Attachment KL-6, SEIA 2.6b

[32] Cost allocation based on LRS_WP11DR Cost of Service Study Model, mapping the Revenue Requirement Including Fair Value Increment on tab Cost of Service to the main allocators used.

	Using Site	Using Delivered	Primary Classification	Approx. Cost Allocated	Residential Over-Allocation
AED	59.54%	58.88%	Production Demand	$1,091,040,740	$7,194,500
4CP	61.06%	60.04%	Transmission Demand	$177,887,325	$1,805,364
Class	60.59%	60.05%	Primary Dist. Demand	$428,941,246	$2,333,076
Ind Max	64.46%	63.79%	Secondary Dist. Demand	$162,961,126	$1,090,466
Energy	48.80%	47.98%	Production Energy	$1,000,125,685	$8,201,418
Total					**$20,624,824**

Table 3 - Residential Share of Key Allocators Under Site and Delivered Load

Q48. DOES THE SOLAR CREDIT ADJUST FOR THIS?

A48. I do not believe it does, but the CCOSS produces unexpected results when changing the allocators to delivered load and removing the solar credit. When I change the allocators to be based on the LRR delivered information and zero out the solar credit, the residential share of the total allocators falls as expected. However, despite having a lower allocators across the board, the residential class ends up with a revenue requirement that is roughly $18 million higher.

Q49. PLEASE DESCRIBE THE PROCESS THAT THE COMPANY USES IN ITS CCOSS RELATED TO SITE LOAD AND THE SOLAR CREDIT.

A49. The Company uses the site energy LRRs for solar customers as inputs into the Allocator WP. The allocation factors are inputted into the CCOSS and used to assign costs to solar subclasses. A separate tab in the CCOSS calculates the solar credit. This process involves determining the revenue requirement for each solar subclass separately for production, transmission, and distribution. Once the revenue requirement is determined, the Company calculates the difference between the site and delivered allocators, and applies a credit to the solar customers separately for production demand ($19.4 million based on 4CP and NCP), transmission demand ($6.7 million based on 4CP), and distribution demand ($5.3 million based on NCP and Individual Max).[33]

The Company makes an additional adjustment to the transmission credit. It first calculates the credit in the same manner as the production and distribution credit, but then

[33] LRS_WP11DR Cost of Service Study Model, tab "Solar Credit"

calculates the difference between transmission revenue and the CCOSS' calculation for allocated transmission costs based on the site 4CP allocator. Since the CCOSS calculates a higher value based on the site 4CP allocator than revenue collected from the solar class, the solar "credit" for transmission turns into a large negative number. For the four solar subclasses, this subsequent adjustment reduces the transmission credit by roughly $13.6 million, turning the transmission demand credit from a positive $6.7 million a negative $6.9 million.

The energy solar credit is not calculated within the CCOSS. Rather, it, like many other values, is simply hardcoded based on an imported file. The energy solar credit totals $35.3 million, details of which needed to be extracted through a discovery question. The Company takes the production data from solar customers, grosses it up to the generation level to adjust for line losses, and then applies the average avoided energy rate of $0.02895 / kWh for the Legacy Energy subclasses and $0.030667 / kWh for the New Solar subclasses.[34]

In total, the solar credit contained in the CCOSS is $53.1 million, producing a net revenue requirement of $182.5 million for the solar subclasses. The value of the solar credit is collected from non-solar residential and non-residential classes based on the corresponding allocators (e.g. AED, 4CP, NCP, and Ind Max) excluding the solar customers. In total, non-solar residential customers provide $28.5 million of the credit with non-residential commercials providing the remaining $24.6 million.

Q50. WHERE THE SITE AND DELIVERED DEMAND VALUES THAT THE COMPANY USED FOR THE SOLAR CREDIT THE SAME ONES USED FOR COST ALLOCATION?

A50. No. Cost allocation for demand costs is done through four primary allocators: AED for production, 4CP for transmission, Class NCP for primary distribution, and Ind Max for secondary distribution. AED is a mathematical formula that is based on the single CP hour demand level and the single hour Class NCP value. Ind Max is also based on a single hour.

---

[34] Attachment KL-15, SEIA 4.3.

However, the solar credit was calculated based on the six-month summer average of the Class NCP and Ind Max (the 4CP is already the average of the four core summer months). Further, the solar credit for production was not based on the AED allocator, but instead based on the average of the 4CP and Class NCP demands.

Q51. DID THE COMPANY EXPLAIN WHY IT CHANGED THE ALLOCATORS WHEN CALCULATING THE SOLAR CREDIT AS COMPARED TO WHEN IT ALLOCATED COSTS TO THE SOLAR CUSTOMERS?

A51. When asked, the Company responded:

> The solar credit is based on the average summer values because they are more representative of the solar contribution to NCP and Ind Max. For example, the solar performance during one particular NCP hour in the summer could vary considerably depending on weather conditions or other factors. This same risk would not be very likely for the entire load of the home without solar. This is the same method APS used in the COS/VOS proceeding (Decision No. 75859) and in its last rate case.[35]

Q52. GIVEN THE COMPANY IS CONCERNED ABOUT THE RISK OF PERFORMANCE DURING A SINGLE HOUR FOR THE CALCULATION OF THE SOLAR CREDIT, WAS IT ALSO CONCERNED ABOUT COSTS THAT ARE ALLOCATED TO SOLAR CUSTOMERS BASED ON A SINGLE HOUR?

A52. No. When asked if it shared this concern with the allocation of costs to solar customers in the CCOSS, it replied "The costs associated with the site load were allocated on the same basis as all other residential rate classes and appropriately reflect the drivers for those costs."[36]

Q53. WHAT IS YOUR RESPONSE TO THIS?

A53. While it is true that costs were allocated to solar customers based on single hours in the same manner as all other residential rate classes, I do not agree that this is the most appropriate method of allocating costs in a modern utility with increasing levels of distributed resources, renewable resources, and advanced metering infrastructure. This is a perfect example of why traditional cost allocation methods are no longer the best fit for modern utilities and need to evolve along the lines of the RAP Manual I discussed previously.

[35] Attachment KL-16, SEIA 4.8c.
[36] Attachment KL-17, SEIA 9.8.

Q54. RETURNING TO THE CHOICE OF ALLOCATORS IN THE SOLAR CREDIT, DOES THE USE OF THE AVERAGE OF THE 4CP AND THE CLASS NCP INSTEAD OF THE PROPER AED ALLOCATOR FOR THE PRODUCTION DEMAND SOLAR CREDIT MAKE A NOTICEABLE DIFFERENCE?

A54. Yes. With the caveat that I do not believe the site load / solar credit method is correct, if APS is going to use it, the Company should be consistent. The difference between the delivered and site AED allocator is considerably higher than the average of the 4CP and Class NCP. Where the production demand credit for the four solar classes is between 23% and 31% using the average of 4CP and Class NCP, it is between 31% and 40% using the AED allocator. When applied properly, this increase the production demand solar credit by $6.2 million, from $19.4 million to $25.6 million.

Q55. IS THE SOLAR CREDIT FULLY INCORPORATED INTO THE CCOSS OR APPLIED AFTER THE REVENUE REQUIREMENT IS FOUND?

A55. It is fully incorporated. Rather than simply adjusting the final revenue requirement for each subclass at the end of the process, the Company treats the solar credit (and revenue from other classes needed to provide the solar credit) as a debit or credit to O&M expenses. Because of this, the CCOSS also adjusts cost such as income tax expenses and proforma adjustments related to taxes.

Q56. IS THE SOLAR CREDIT A REAL CREDIT IN THE SENSE THAT IT IS BEING PAID TO SOLAR CUSTOMERS AND CHARGED TO NON-SOLAR CUSTOMERS, AND THEREFORE SHOULD IMPACT COST CATEGORIES SUCH AS INCOME TAX?

A56. No. The solar credit is a construct that is contained to the CCOSS. It exists solely as result of the Company's choice to allocate costs based on site load instead of delivered load. I am unclear why the Company chose to include it in the O&M expense category, which subsequently impacts issues such as income tax allocation between the classes.

Q57. IF ALLOCATORS WERE BASED ON DELIVERED LOAD AND THE SOLAR CREDIT REMOVED, WHAT HAPPENS TO THE REVENUE REQUIREMENT FOR SOLAR AND RESIDENTIAL CUSTOMERS?

A57. One would think that costs allocated to solar customers would remain roughly the same, assuming the difference between the site-allocated costs and the credit for the difference between site and delivered load was performed properly. One would also think that the costs allocated to the residential class as a whole would fall slightly due to the lower share of total residential demand allocators compared to the entire ACC jurisdiction total, as shown in Table 3 above.

Q58. IS THIS WHAT OCCURS?

A58. No. When delivered load allocators are used and the solar credit is removed, the ratebase assigned to the residential class does fall by roughly 0.6%, which is in line with the expected reduction based on the allocators. However, there are differences in the expense categories that overwhelm the reduction in the return on asset expense. The cost to solar customers increases by $16.7 million, and the cost to non-solar residential customers increases by $1.2 million. In total, the revenue requirement for all residential customers increases by roughly $17.9 million.

Q59. WERE YOU ABLE TO TRACE THE ORIGIN OF THESE DISCREPANCIES?

A59. Not entirely. They appear to be related to the way the CCOSS allocates expenses. For instance, when removing the solar credit but keeping allocators based on site load, the total O&M cost for solar customers increases by $53.4 million, the exact amount of the solar credit. This is an expected result. However, when one subsequently changes the allocators to be based on delivered load, the total O&M cost only falls by $44.7 million, leaving an $8.7 million gap. The remainder of the difference appears to be related to the manner in which the change in O&M costs impact cost categories such as income tax, proforma adjustments, and system benefits allocations that are built on this gap.

Q60. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A60. The use of site energy is incorrect in the first place. The creation of a solar credit, which includes an energy credit calculated outside of the CCOSS and a transmission credit that is further adjusted, adds needless complexity to an already complex model. Switching from the Company's site / solar credit method to a delivered / no solar credit method should produce a result where solar customers see the same cost and the residential class as a whole sees slightly lower costs. This is not what occurs. Even if the results were identical between these two methodologies, for the sake of simplicity and transparency, the Commission should direct the Company to use the delivered / no solar credit method in its CCOSS.

In the event that the Commission does prefer the site / solar credit methodology, it should require that the Company use the proper AED allocator for production demand costs, and not the average of 4CP and Class NCP as it currently does.

The Company's CCOSS methodology and workpapers are Opaque, Contain Errors, and Do Not Conform to the Commission's Directives.

Q61. HOW DID YOU FIND WORKING WITH THE COMPANY'S VARIOUS WORKPAPERS AND MODELS RELATED TO THE CCOSS?

A61. I found them rather frustrating to work with. The Company's LRRs contained 103 different reports, with many of the reports representing the sum of other reports. These reports were not linked to each other, and the names of the reports were neither consistent with the CCOSS class names nor with the tariffs. The Company should have used consistent names between the tariffs, LRRs, and CCOSS, and it should have provided a hierarchy for the LRR without one having to ask for it in discovery.

The Allocation WP was not linked to the LRR; rather, the data was shown as hardcoded values. Further, the Company for some reason decided to round the values in the Allocation WP to the nearest MW rather than just using the numbers from the LRR. While this did not have that large of an impact on the larger subclasses, it could have a non-trivial impact on the allocation calculation of smaller classes such as the R-Solar Demand, which had a CP value of only 5 MW. Rounding up from 4.5 MW could increase this value by 10%.

The Allocation WPs were not linked to the CCOSS. Instead, the CCOSS had a large tab called "Import" which referenced 30 different individual files with names such as "Plant", "G&I", "W&S", "Rev Acct 454" and so on. These appear to be the source for key values such as revenue from retail rates, which of course were also hardcoded after being imported. When I requested the 30 files that were uploaded to the CCOSS, the Company responded:

> The data from the referenced external files is provided in the "Import" tab below the file references. Thus, SEIA has the values for all referenced information. The file references are simply the mechanics of how that data gets imported into the model. To the extent that SEIA is seeking additional source data and/or all files from which these values were derived, APS objects to this data request as cumulative and unduly burdensome.[37]

Apparently, the Company expects intervenors to simply trust that its figures are correct. This lack of transparency is always problematic, particularly considering the Company's workpapers contained numerous errors that only came to light through the discovery process, as discussed below.

The rest of the CCOSS was complex, but reasonably well organized. There were times when deciphering the style of formula the Company used was challenging given the many nested lookup references it used. This required one to partially evaluate the formula to determine the references, and only then look up the values that were being used. As a particularly challenging example of this issue, this is the formula used to calculate the Production Revenue credit portion of the solar credit.

```
=(+IF(ISERROR(SUMIF(INDEX(INDIRECT($L103),0,FERC_Col),$M103,INDEX
(INDIRECT($L103),0,Amount_Col))*@INDEX(INDIRECT('Cost of Service'!
$AT$3),MATCH($N103,INDIRECT('Cost of Service'!$AT$4),0),'Cost of
Service'!M$1)),0,SUMIF(INDEX(INDIRECT($L103),0,FERC_Col),$M103,INDEX
(INDIRECT($L103),0,Amount_Col))*@INDEX(INDIRECT('Cost of Service'!
$AT$3),MATCH($N103,INDIRECT('Cost of Service'!$AT$4),0),'Cost of
Service'!M$1)))+(+IF(ISERROR(SUM(INDEX(INDIRECT($O103),0,MATCH($P1
03,Mapping!$3:$3,0)))*@INDEX(INDIRECT('Cost of Service'!$AT$3),
MATCH($Q103,INDIRECT('Cost of Service'!$AT$4),0),'Cost of Service'
```

[37] Attachment KL-18, SEIA 2.6a.

!M$1)),0,SUM(INDEX(INDIRECT($O103),0,MATCH($P103,Mapping!$3:$3,0))) *@INDEX(INDIRECT('Cost of Service'!$AT$3),MATCH($Q103,INDIRECT('Cost of Service'!$AT$4),0),'Cost of Service'!M$1)))+(+IF(ISERROR(SUM(INDEX (INDIRECT($R103),0,MATCH($S103,Mapping!$3:$3,0)))*@INDEX(INDIRECT(' Cost of Service'!$AT$3),MATCH($T103,INDIRECT('Cost of Service'!$AT$4) ,0),'Cost of Service'!M$1)),0,SUM(INDEX(INDIRECT($R103),0,MATCH ($S103,Mapping!$3:$3,0)))*@INDEX(INDIRECT('Cost of Service'!$AT$3) ,MATCH($T103,INDIRECT('Cost of Service'!$AT$4),0),'Cost of Service'!M$1))) +(+IF(ISERROR(SUM(INDEX(INDIRECT($U103),0,MATCH($V103,Mapping!$3: $3,0)))*@INDEX(INDIRECT('Cost of Service'!$AT$3),MATCH($W103, INDIRECT('Cost of Service'!$AT$4),0),'Cost of Service'!M$1)),0,SUM(INDEX (INDIRECT($U103),0,MATCH($V103,Mapping!$3:$3,0)))*@INDEX(INDIRECT(' Cost of Service'!$AT$3),MATCH($W103,INDIRECT('Cost of Service'!$AT$4),0), 'Cost of Service'!M$1)))

Q62. WAS THE MATTER OF THE COMPANY'S CCOSS MODELS A SUBJECT OF DISCUSSION IN PREVIOUS CASES?

A62. Yes. In Docket No. E-00000J-14-0023, there was extensive discussion related to the Company's use of a proprietary "black box" CCOSS model. In that case, intervenors were unable to even get access to the model, and the Company would not perform alternative scenarios to test the impact of changing the CCOSS inputs.[38] This deficit was so severe that the Commission determined it had no record to support approval of a specific CCOSS methodology:

> However, absent an ability to review and compare the alternate scenarios with varied inputs and assumptions that all the parties would have been able to present with a fully functional model, we are left with a record that does not support approval of a specific COSS methodology in this proceeding. [] It will be of utmost importance in upcoming electric utility rate cases for all parties to be on equal footing with regard to the ability to use the cost of service model to illustrate their positions.[39]

Q63. WHAT DID THE COMMISSION ORDER TO RECTIFY THIS ISSUE?

A63. The Commission directed utilities to improve the transparency, accessibility, and flexibility of their models in all pending and future rate cases:

> 160. Utilities will be directed to submit cost of service studies in rate cases, both pending cases and in future rate cases, which are based on models with spreadsheets containing links between inputs and outputs which are available to all parties. The cost of service study models used by the utilities shall be:

[38] Docket NO. E-00000J-14-0023, Decision 75859 at 15, 21.
[39] Docket NO. E-00000J-14-0023, Decision 75859 at 144.

> 1) Transparent: all inputs, assumptions and calculations shall be clearly described and explained,
> 2) Accessible: have electronic spreadsheets with links between inputs and outputs made available to all parties, and
> 3) Flexible: to allow for the ability to change inputs and assumptions used in the calculation.

Q64. DO THE WORKPAPERS AND MODELS THAT APS USED IN THIS CASE MEET THESE CRITERIA?

A64. No, they do not. The workpapers were not transparent as required by the Commission. Calculations were coded using indirect reference lookups with no explanation of how data flowed from one section to another. While some of the hardcoded input files had useful notes, many were missing notes entirely or contained "notes" such as "Plug to tie to C-1", "FC Common", "Plug a negative 18k", "Check", and "THIS CELL DOES NOT LINK AND NEEDS TO BE UPDATED MANUALLY FROM CERT 19 IF BTL ADJ IS NEEDED."

The workpapers were not accessible as required by the Commission. While the individual workpapers contained formulas that allowed for one to change inputs and calculate different outputs, there were no linkages between the files themselves. In order to update the Allocation WP based on the delivered LRR, I needed to relink the files myself. To update the CCOSS with new Allocation WP values, I had to complete a tedious and error-prone process to overwrite hardcoded values that used different references for allocator and subclass names in the CCOSS than in the Allocation WP. Further, the company objected as "unduly burdensome" a request to produce the workpapers that formed the basis of the hardcoded values imported into the CCOSS.[40]

The workpapers were not flexible and required by the Commission. Only after reverse engineering these linkages was I able to modify the CCOSS based on different inputs that would flow from one end of the process to the other. Further, when errors were found during discovery that impacted the solar credit calculation, the Company did not provide updated working models, but rather a hardcoded extract from the CCOSS.[41] I had to

[40] Attachment KL-18, SEIA 2.6a.
[41] Attachment KL-19, SEIA 4.8a.

manually update the CCOSS using the hardcoded values to determine how the rest of the model was impacted.

Q65. WHAT OTHER DIRECTIVE DID THE COMMISSION GIVE TO UTILITIES REGARDING THEIR CCOSS?

A65. The Commission provided specific directions on how to calculate class NCP demands in the CCOSS, which APS has disregarded in this case. In UNS Electric Inc's ("UNSE") previous rate case, the utility proposed a CCOSS that allocated distribution costs based on the Class NCP allocator.[42] UNSE proposed that the Class NCP for solar customers be based on either the import or export of energy and be set based on the maximum value of either independent of the peak of the class entire residential class. Under UNSE's assumptions, the DG Class NCP occurred in April, while the combined DG / non-DG Class NCP occurred in July.[43]

The Commission considered the arguments for and against this methodology, and determined that UNSE was in error in calculating a Class NCP for the DG class that did not coincide with the entire residential class of both DG and non-DG customers:

> The Companies utilized the class NCP method which determined the NCP for the non-DG and DG classes separately to allocate the distribution costs between DG and non-DG customers. However, usage of the grid during times other than the net combined NCP of the DG and non-DG classes should not be factored into the allocation of the distribution costs as it does not drive distribution capacity costs. Since the combined NCP for the DG and non-DG customer classes occurs in the summer, the DG class NCP, based on exports in April, does not impact the cost of the distribution circuit as there is plenty of excess capacity at that time...
>
> Because the net combined residential NCP occurs in July, this is the basis for allocating the distribution circuit costs, and it is irrelevant that the DG customers' NCP occurs in April because the circuit must be built to serve the maximum total residential capacity which occurs in July. No additional cost is incurred to serve the DG customers' NCP…
>
> [T]he Companies' use of the separate class NCP demands instead of the relative demands each class places on the distribution system at the time of their combined maximum demand, does not attribute the cost of the distribution system in proportion

[42] Docket No. E-04204A-15-0142, IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUSTAND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.

[43] Docket No. E-04204A-15-0142, Decision 76900 at 83.

to cost causation between the DG and non-DG classes, and thus, it is inequitable. The potential impact could be, and likely is, significant, but we cannot know the full effect until the Companies revise their CCOSSs to reflect a more equitable allocation based on the relative demands of each class at the time of their combined maximum demand.[44]

Q66. HOW DID APS CALCULATE CLASS NCP FOR ITS VARIOUS RESIDENTIAL SUBCLASSES?

A66. It calculated the value based on the maximum hour of site energy of solar subclasses and delivered energy of non-solar subclasses, regardless whether the peak coincided with the total residential class peak. Table 4 below shows the peak demand of the total residential class and the independent peaks for the CCOSS subclasses, along with corrected values for both site and delivered energy based on the actual hour of the total residential class peak.

[44] Docket No. E-04204A-15-0142, Decision 76900 at 83-84

NCP Demand (MW)	Independent Class NCP		Site Class NCP at Res Peak		Del Class NPC at Res Peak	
	NCP	Timestamp	NCP	Delta %	NCP	Delta %
Total Residential	4,022.7	Aug 5th @ 18:00	4,022.8		4,022.8	
Independent Subclass Sum	4,271.9		4,141.9		4,022.8	
Excess NCP Demand	6.2%		3.0%		0.0%	
CCOSS Subclasses	NCP	Timestamp	NCP	Delta %	NCP	Delta %
Legacy Solar – Energy	412.1	Jul 24th @ 18:00	380.8	-7.6%	275.8	-33.1%
Legacy Solar – Demand	26.5	Aug 5th @ 17:00	24.8	-6.6%	18.5	-30.1%
New Solar – Energy	53.8	Jun 29th @ 17:00	19.2	-64.3%	13.0	-75.9%
New Solar – Demand	22.2	Jun 29th @ 17:00	5.2	-76.5%	3.5	-84.0%
R-XS	367.3	Jul 24th @ 18:00	361.0	-1.7%	361.0	-1.7%
R-Basic	407.5	Jul 24th @ 18:00	390.8	-4.1%	390.8	-4.1%
R-Basic LRG	248.6	Jul 24th @ 18:00	238.4	-4.1%	238.4	-4.1%
R-TOU No Solar	1,551.0	Aug 5th @ 17:00	1,542.7	-0.5%	1,542.7	-0.5%
R-Demand No Solar	1,183.0	Aug 5th @ 17:00	1,179.1	-0.3%	1,179.1	-0.3%

Table 4 - Independent Class NCP vs. Total Residential Class NCP

Exactly zero of the independent subclass peaks occurs during the total residential Class NCP hour of August 5th, 2018 between 5 PM and 6 PM. Under the "independent" Class NCP method, the sum of the Class NCP allocators is 6.2% higher than it should be. Under the APS's erroneous site load definition, the Company is still producing figures that are 3.0% higher than based on the total residential Class NCP. Only when the proper delivered energy is used does the sum of the subclass Class NCP demands equal the total residential Class NCP demand value.

Further, the difference between the independent and total residential-aligned Class NCP for solar subclass values – as anticipated by the Commission itself – are "significant". The New Solar subclasses see their delivered Class NCP demand value fall by 76% to 84%, with the Legacy Solar subclasses experiencing a smaller, but still sizable, reduction between 30% and 33%. Even the non-solar customers see a reduction in their Class NCP values, properly reflecting the diversity of demand that occurs across a large number of customers.

Q67. WHAT DO YOU RECOMMEND WITH REGARD TO THIS ISSUE?

A67. I recommend the Commission reject the Company's current methodology of using independent Class NCP hours for its various subclasses and instead required an updated

CCOSS that aligns subclass Class NCPs with combined total residential class as was previously ordered for UNSE.

Q68. DID YOU FIND OTHER ERRORS IN THE COMPANY'S WORKPAPERS?

A68. Yes. While it is not unusual for an undertaking as complex as a utility CCOSS to contain mistakes, this underscores the need for robust transparency to ensure these mistakes can be found and corrected. Further, when mistakes are found, the Company should provide fully functional, updated workpapers that contain the revised information. This was not done; instead, the Company provided hardcoded excerpts of workpapers with the updated information.

Some of the errors I found were minor, others were more significant. I previously discussed the improper use of the production allocator for the solar credit, which reduced the value of the solar credit by roughly 10%. The Company also used the wrong meter costs for solar customers, overstating the total meter costs by 23%.[45] When spread over the entire solar fleet, this leads to an over-calculation of meter costs of $9.5 million, which drives further cost increases in the CCOSS.

The Company had incorrect customer counts in the LRR for many of residential customer groupings. Essentially, the Company duplicated December 2018 customer counts into January 2019, and thus the June 2019 customer counts – which were used in the Allocation WP – reflected May 2019 and not June 2019.[46] Given that several customer classes showed substantial customer growth or loss during the test year, this error resulted in customer counts that were understated by 6.5% and 5.3% for the R-Solar Demand and R-Solar TOU classes, and overstated by 1.8% for R-Basic and 1.9% for R-Basic Large. These errors ripple through the CCOSS for all costs that are allocated based on customer counts.

[45] Attachment KL-20, SEIA 11.5.
[46] Attachment KL-21, SEIA 10.3.

Q69. ARE THERE OTHER METHODOLOGICAL ISSUES THAT YOU FOUND WITH THE COMPANY'S WORKPAPERS?

A69. Yes. I have previously discussed the primary issue of using site energy instead of delivered energy, but the Company made several other choices that I do not agree with. The first involves adjustments made to the subclass load shapes. The Company begins with billing information for roughly 750,000 of its 1.1 million customers that had complete data for the test year. A load shape is calculated for each class, and then is grossed up based on the number of customers missing data. After this is done, the Company applies "demand adjustors" to conform the billing data peak demand to the total system peak as reported on the Company's FERC Form 1.

These demand adjustments are only applied to the delivered load of customer groups, but not to the site load of solar customers. Further, the adjustments are quite large in the summer months; they range from -5.7% to -6.6%.[47] By applying these demand adjustments to non-solar residential customers but not solar residential customers, the Company further widens the gap between the site and delivered energy in its CCOSS.

While the Company adjusts the demand information from the billing system, it does not make corresponding adjustments to the energy levels. When comparing energy usage from the billing information to the LRR, there are instances of large disagreement in monthly and total usage in some subclasses. Although the CCOSS does not use energy allocators other than total energy, the inconsistency between the census billing data and the LRR results is somewhat troubling. I recommend the Company provide more detail about how its load shapes are established in future rate cases.

[47] Attachment KL-22, SEIA 4.10.

Q70. YOU MENTIONED THAT CERTAIN CUSTOMER SUBCLASSES EXPERIENCED HIGH GROWTH OR SHRINKAGE OVER THE TEST YEAR. DID THE COMPANY ADJUST FOR THIS IN ITS CCOSS?

A70. No, it did not, and the issue is exacerbated by the usage of a mid-year to mid-year test year. In general, the number of customers taking service under the New Solar – Energy (+8,581 customers) and New Solar – Demand (+3,372) rates grew, while the number of customers on the Legacy Solar rates remained close to level. Meanwhile, the non-solar R-Basic Large (-18,337) and R-Basic (-27,448) saw considerable customer erosion, while the R-TOU No Solar (+17,310) and R-Demand No Solar (+23,614) saw relatively small percentage increases but large customer increases. Figures 2 and 3 below show the growth trend over the test year for the solar and non-solar customer subclasses, respectively.

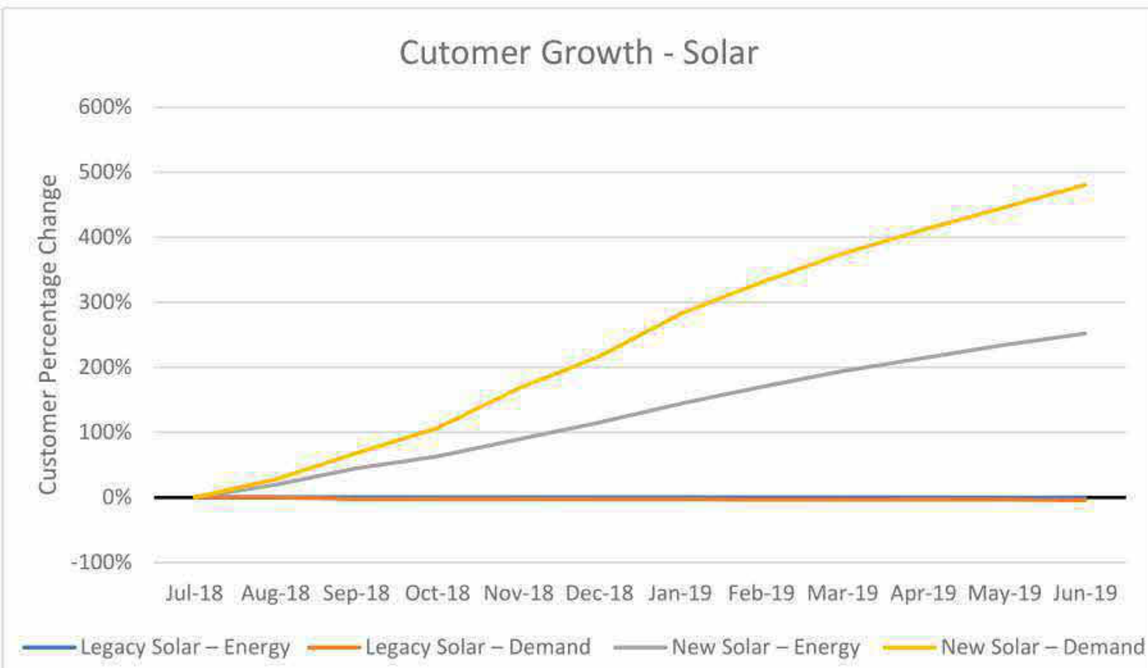


Figure 2 - Customer Growth – Solar

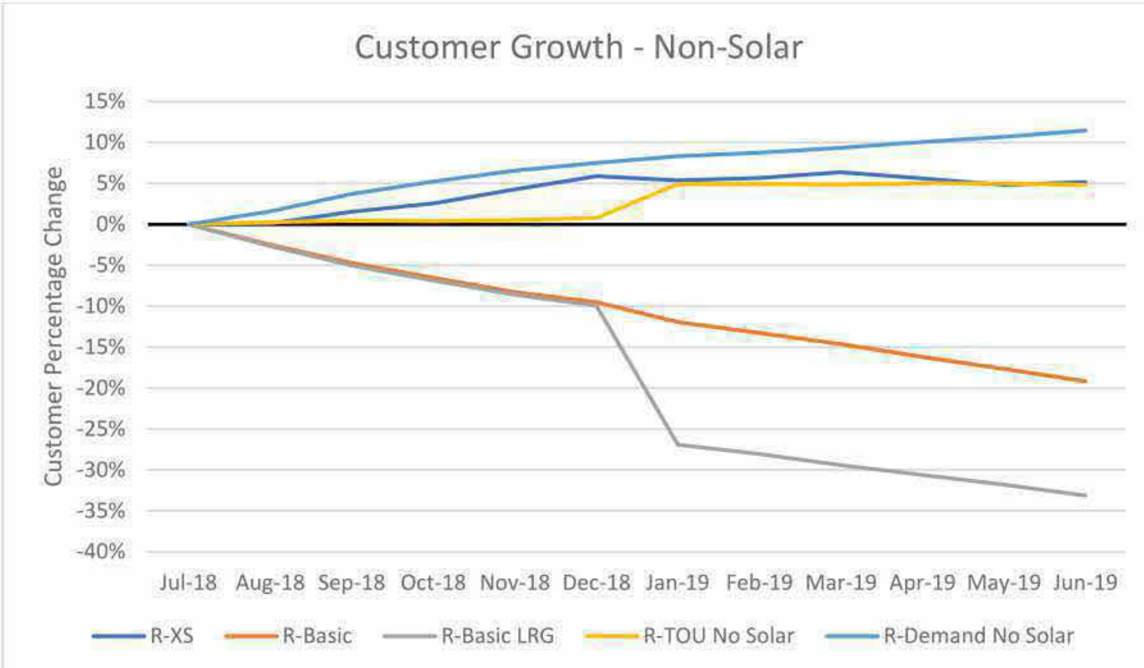


Figure 3 - Customer Growth - Non-Solar

Q71. WHAT IS THE IMPACT OF THIS CUSTOMER GROWTH ON THE ALLOCATORS USED IN THE CCOSS?

A71. Because the system CP occurred during July 2018, the first month of the test year, the absolute demand values for classes with positive growth were lower than they would otherwise be as the number of customers was lower in the first month than in the last month. Likewise, for customer classes that saw customer decreases, the CP value would be higher than otherwise. The 4CP values are also impacted, with three of the four values (July, August, and September) coming at beginning of the test year before the bulk of the customer count changes took hold.

Q72. WHAT CUSTOMER COUNT FIGURE DID APS USE IN THE CCOSS?

A72. APS used the final customer count in the CCOSS, although as mentioned before, these values incorrectly represented May 2019 instead of June 2019. Regardless, by using the final customer counts for customer allocators, subclasses with customer growth (such as solar customers) were over-allocated customer costs compared to the average number of customers during the test year, while subclasses with customer reductions were under-allocated customer costs.

Q73. HOW COULD THE COMPANY ADJUST FOR THIS ISSUE IN ITS CCOSS?

A73. As a first matter, the Company can simply use fewer subclasses in its CCOSS. The total residential class sees very little customer variation over the course of the year, growing roughly 1.8%. However, if the Commission approves the Company's use of myriad subclasses, the Company can develop a load shape that is based on per-capita load rather than absolute load. This can be done by converting hourly loads in each subclass to per capita loads, and then expanding the per capita loads by the average number of customers in the subclass over the year. This will smooth out the disjunction in load between June and July that is caused by a year's worth of customer increase or decrease and result in more appropriate demand allocators based on individual summer hours.

Q74. WOULD THIS TYPE OF ADJUSTMENT BE UNUSUAL?

A74. No. The Company already makes sizable adjustments to its billing data to produce its load shapes, including normalizing individual month peak demands with 12 different demand adjustors and using FERC Form 1 values for energy rather than results from the monthly billing data. Creating a per-capita-based load shape and multiplying it by the average number of customers would provide an appropriate adjustment to the sizable load growth and shrinkage that the Company is currently experiencing in its residential customer subclasses.

The Company's CCOSS Flaws result in an Overstatement of the Cost to Serve Solar Customers

Q75. DID YOU CORRECT THE ERRORS AND METHODOLOGICAL INCONSISTENCIES WITH THE COMPANY'S CCOSS?

A75. Yes. After I reverse-engineered the links between the Company's LRRs, the Allocation WP, and the CCOSS model, I produced an updated set of workpapers that enabled me to calculate a new cost of service for solar customers.

Q76. PLEASE DESCRIBE THE MODIFICATIONS THAT YOU TOOK.

A76. I began with data the Company provided that was used to derive the LRRs.[48] This data included unadjusted hourly load data for each of the residential subclasses. Using corrected data for customer counts, I first developed a per-capita hourly load profile and then expanded the per-capita figures based on the average number of customers in each class. This adjustment smoothed out the impact of sizable customer growth and shrinkage in the various subclasses. Based on these updated load profiles, I calculated new load characteristics for CP, 4CP, and Class NCP. Per the Commission's directives, I used the hour that corresponding to the total residential Class NCP for all subclass Class NCP values. I was not provided the data to recalculate the Ind Max allocator from the billing data, but I was able to adjust the Company's original values for delivered load based on the customer count in the month during which the Ind Max peak was set. From here, I linked a modified version of the CCOSS to an updated Allocator WP file. This allowed the new allocators to flow into the CCOSS. I removed all formulas related to the solar credit as this was rendered superfluous by using delivered load.

Q77. DID THESE ADJUSTMENTS ONLY REDUCE THE COST TO SERVE SOLAR CUSTOMERS?

A77. No. While some of these changes may have benefitted solar customers, others did not. Adjusting the demand values for customer growth actually produced higher demand values for the CP, 4CP, and Class NCP allocators for solar customers, which in turn led to more costs being allocated than had I carried over the Company's method. Removing the solar credit for energy removes a credit for solar customers for self-consumed energy which is not otherwise captured in the CCOSS. Regardless of this result, the goal of my updates was not to produce the lowest cost for solar customers, but to instead produce a more robust and accurate CCOSS.

[48] Attachment KL-22, SEIA 4.10.

Q78. WHAT WAS THE RESULT OF YOUR UPDATED CCOSS?

A78. I find that the combination of using delivered load allocators, resolving errors, using the Commission-directed Class NCP method, and adjusting for customer growth reduced the cost to serve the solar subclasses by approximately $6.1 million, from a total of $182.3 million in its original filing to $176.2 million under my update, as seen in Table 5 below.

$mm	Updated SEIA CCOSS	Original APS CCOSS	Delta	Delta %
Total Residential	$1,976.2	$1,974.6	$1.6	0.1%
All Solar	$176.2	$182.3	($6.1)	-3.3%
All Non-Solar	$1,800.0	$1,792.3	$7.6	0.4%
Legacy Solar – Energy	$149.6	$155.3	($5.7)	-3.7%
Legacy Solar – Demand	$8.9	$7.8	$1.1	14.7%
New Solar – Energy	$13.1	$14.5	($1.4)	-9.5%
New Solar – Demand	$4.6	$4.7	($0.2)	-3.2%
R-XS	$233.3	$233.2	$0.1	0.0%
R-Basic	$178.4	$183.1	($4.6)	-2.5%
R-Basic LRG	$93.9	$99.9	($6.0)	-6.0%
R-TOU No Solar	$734.0	$723.9	$10.2	1.4%
R-Demand No Solar	$560.3	$552.3	$8.0	1.5%

Table 5 - Updated vs. Original CCOSS Results

Q79. HOW DO YOU INTERPRET THESE OVERALL RESULTS?

A79. There are two changes that occur between the updated and original results. The first relates to the use of the delivered load allocators rather than site allocators. As discussed previously, this should have resulted in a reduction of the total residential cost allocation due to the smaller share of the zero-sum total jurisdictional allocator. However, the results above do not bear that out. The second relates to the unwinding of the solar credit. It is possible that additional income tax and proforma adjustments related to the Company's implementation of the solar credit is responsible for the residential class seeing a small increase in costs. It is also possible that the decision to bring into the CCOSS the energy savings associated with the whole of solar production overstated the savings that were attributed to solar customers under the site / solar credit methodology. Regardless of whether the Company agrees with the use of delivered load allocators for solar customers, I recommend the Commission require the Company to demonstrate why the use of delivered load allocators in its CCOSS results in a higher total residential revenue requirement than the site / solar credit methodology despite the former resulting in a smaller sum of allocators.

Q80. ARE THERE OTHER WAYS TO LOOK AT THIS DATA THAT SHEDS LIGHT ON THE RELATIVE COST TO SERVE DIFFERENT CUSTOMER SUBCLASSES?

A80. Yes. Because the CCOSS contains each of the allocators applied to different functionalized costs (e.g. production, transmission, energy, etc.), one can calculate the effective cost per unit of allocator. Figure 4 below shows these results. The Legacy Solar subclasses are in green, the New Solar subclasses in orange, and the non-solar subclasses in blue, along with the total average residential value in red.

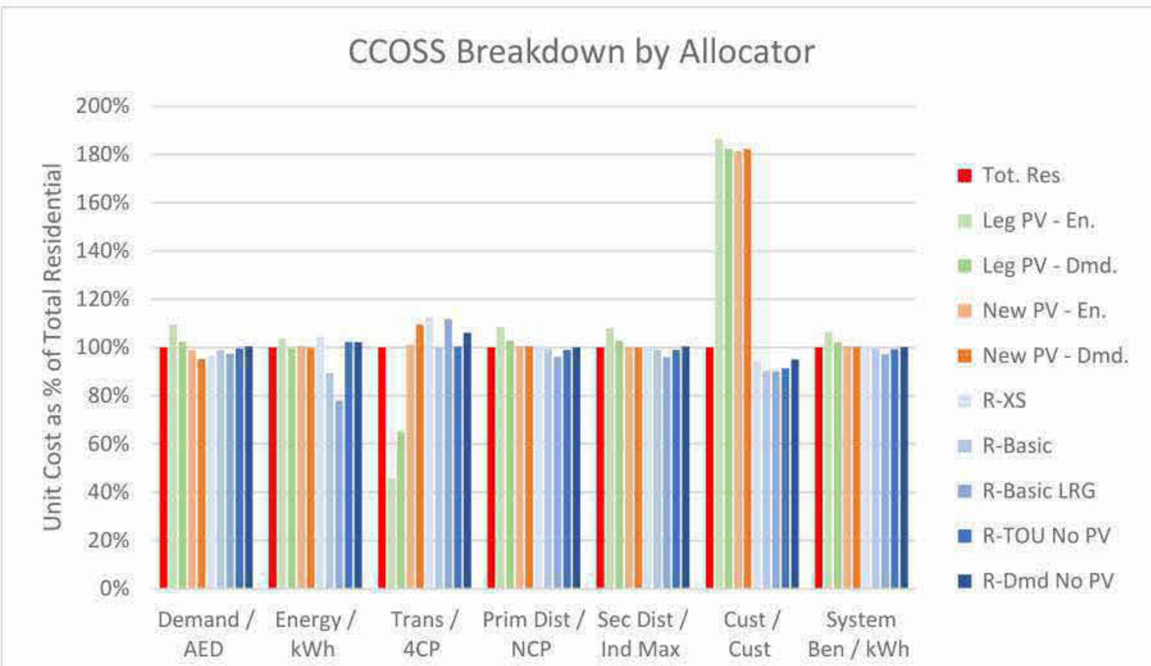


Figure 4 - CCOSS Breakdown by Allocator

There are only a few instances in which the any of the subclasses are materially different from the total residential values or from each other. The first is for the Legacy Solar subclasses for transmission, where these subclasses have a lower transmission cost per 4CP result than the rest of the subclasses. The second is the energy costs per kWh, where the R-Basic and R-Basic Large have somewhat lower costs per kWh than solar customers, the new non-solar rates, or the total residential class. The final is customer costs, where solar customers have a much higher cost than the total residential class. For all other values, the results of all of the solar subclasses are very similar to both the total residential class and non-solar customers.

Q81. ARE THERE CAVEATS REQUIRED FOR THIS ANALYSIS?

A81. Yes. The unit cost results above are a function of two values: the classified costs allocated in the numerator, and the value of the allocator (e.g. kWh or NCP kW) in the denominator. When subclasses differ from the overall residential average, it can be because more or fewer costs in this category were allocated compared to other subclasses with the same allocator values, or that the same costs were allocated but measured against higher or lower values for the allocators. As such, one must be cautious when generalizing the results above to make statements about one customer subclass being more expensive than another.

For instance, it may be tempting to suggest that the Legacy Solar customers have a lower cost of transmission than other solar customers or other non-solar customers. However, the CCOSS has transmission-related adjustments related to non-ACC jurisdictional costs and direct assignments that appear to be outside of the typical allocator method. Given the consistency of the other subclasses, the root cause of the Legacy Solar transmission unit costs may lie outside of the allocation process within the CCOSS.

Q82. WERE YOU ABLE TO TRACE THE CAUSE OF THE LARGE DIFFERENCE IN THE CUSTOMER COSTS FOR SOLAR CUSTOMERS?

A82. Yes. The bulk of the customer cost difference comes from the Company's allocation of customer costs for meters, with a smaller increase due to the relative credits and debits for the E-3 (Residential Energy Support Program) and E-4 (Residential Medical Care Equipment Support Programs). Figure 5 below shows the relative cost per customer for each of the customer-related categories.

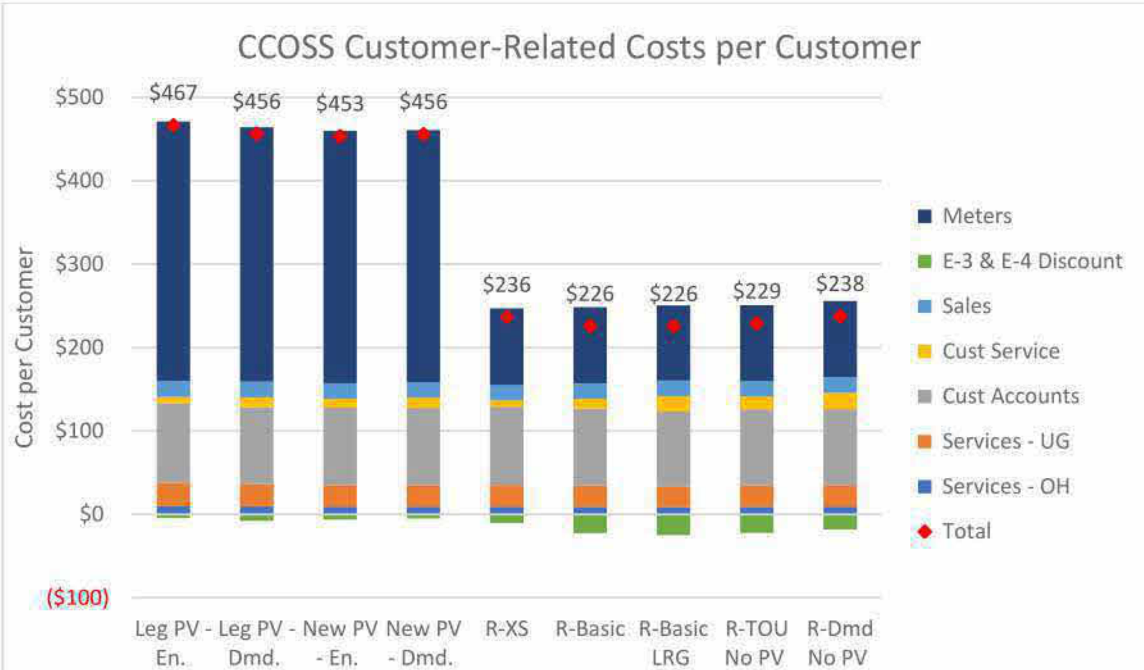


Figure 5 - CCOSS Customer-Related Cost per Customer

The non-meter costs are very similar for each customer category, which makes sense given the nature of those costs. Solar customers take fewer E-3 and E-4 credits than non-solar customers, and given that these costs are recovered across all customer subclasses on a per kWh basis, the net flow of E-3 and E-4 funds is a net cost for the solar customers and a net benefit for the non-solar customers. However, the metering costs are starkly different. On average, solar customers are allocated about $220 per year, or $18 per month, in the CCOSS.

Q83. WHAT DRIVES THE LARGE DIFFERENCE IN METERING COSTS?

A83. There are two factors that drive the metering cost disparity between solar and non-solar customers. The first is that APS requires solar customers to install two meters – one bi-direction meter to measure usage and exports, and a production meter to measure just the generation from the solar system. APS uses a bi-directional meter that is nearly three times as expensive ($310) as its standard AMI meter ($106). It also claims that the "shop cost" required to test and validate the bi-direction meter is more than eight times as expensive.[49]

[49] Attachment KL-20, SEIA 11.5.

Together, the total metering cost for solar customers is $452.83, compared to a total cost for non-solar customers of $137.06.

Q84. WHY DOES APS CLAIM IT NEEDS TO SPEND THIS MUCH ON SOLAR METERING?

A84. While APS admits that production meters are not needed for billing, it states that its solar metering configuration is used

> to determine performance-based incentives for solar customers, to study and monitor the grid impacts from distributed solar, to calculate the Company's Lost Fixed Cost Recovery adjustment, to calculate cost of service, and to track compliance with regulatory mandates. In addition, the Commission requires APS to utilize production meters for compliance purposes. Please see Decision No. 72737 (January 18, 2012).[50]

Q85. COULD SOME OF THESE TASKS BE PERFORMED WITHOUT THE PRODUCTION METER OR WITH A LESS-EXPENSIVE CONFIGURATION?

A85. Yes. Despite the original discovery question explicitly referring to residential meters, and its response that production meters are required for performance-based incentives for solar customers, the Company ultimately admitted that is has *never offered* production-based incentives to residential customers.[51] Further, it has requested a waiver from the Residential DG Carve Out Requirement for program years 2017, 2018, 2019, 2020, and 2021, having received approval in the first three and awaiting approval in the last two.[52]

The "cost of service" reference above likely corresponds to the Company's use of the site load / solar credit process in the CCOSS study. However, as discussed above, this approach is neither necessary nor appropriate. The Company can shift its CCOSS to using the delivered load metric that does not required a production meter.

Finally, modeling of PV systems has become more sophisticated in recent years. While the Company claims it still uses production meters for its Lost Fixed Cost Recovery mechanism, it is certainly possible to model the production of its systems rather than relying on product meter readings. While the accuracy of modeling may be slightly lower than

---

[50] Attachment KL-23, SEIA 7.1
[51] Attachment KL-24, SEIA 31.1
[52] Attachment KL-24, SEIA 31.1

production meter results, this loss of precision must be measured against the millions of dollars in costs that are incurred by requiring production meters.

Q86. WHAT IS THE IMPACT OF THE COMPANY'S SOLAR CUSTOMER METERING CONFIGURATION?

A86. Under my updated CCOSS, which corrects the Company's erroneous metering costs found in its original filing, the revenue requirement associated with the "meters" cost category is $26.8 million for 86,646 solar customers. If the same configuration were used as normal customers, the cost for metering would be just over $8.1 million. The delta between these two values means that every MWh of solar outflow incurs $17.76 in incremental metering expenses. Considering that the bulk of the Company's solar credit for energy is valued at $28.95 / MWh, this means that roughly two-thirds of the benefit the Company ascribes to rooftop solar energy is eaten up through additional metering costs.[53]

Q87. WHAT DO YOU RECOMMEND WITH THIS ISSUE?

A87. I recommend the Commission direct the Company to investigate ways of reducing metering expenses associated with solar customers. Several of the Company's main justifications for production meters – performance-based incentives, regulatory compliance, and cost of service modeling – do not appear to require production meters at all. Even those that do can be transitioned to an alternative approach. Modeling software has increased in sophistication since the Commission required production meters in 2012; determining production for residential solar customers for the Lost Fixed Cost Recovery mechanism could be done through modeling rather than hardware.

Further, it appears that the Company is installing bi-directional meters that are much less expensive than those captured in the CCOSS.[54] Although this change may not have a major impact on the meter costs in the current case, the Commission should direct the Company to properly reflect metering costs based on the future mix of meters in the field rather than simply assuming every customer has the most expensive meter installed.

---

[53] Attachment KL-15, SEIA 4.3

[54] Attachment KL-24, SEIA 31.1

Q88. EVEN WITH THE CURRENT METERING CONFIGURATION, HOW DOES THE TOTAL COST PER CUSTOMER COMPARE BETWEEN SOLAR AND NON-SOLAR CUSTOMER SUBCLASSES?

A88. Figure 6 below shows the total cost per customer from the CCOSS, with the hashed area representing meter costs and the solid area representing non-meter costs. The total cost per customer, which does not account for changes in customer size, shows that the cost to serve solar customers is roughly equivalent for similar-sized customer subgroups. That is, the cost to serve larger solar customers, such as those on the Legacy PV – Demand tariff, are similar to the cost to serve large non-solar customers, such as those on the R-Demand No Solar tariff. Likewise, medium-sized solar customers are similar to medium-sized non-solar customers. The sizable differences in metering costs is a clear contributor to the overall difference in total cost per customer.

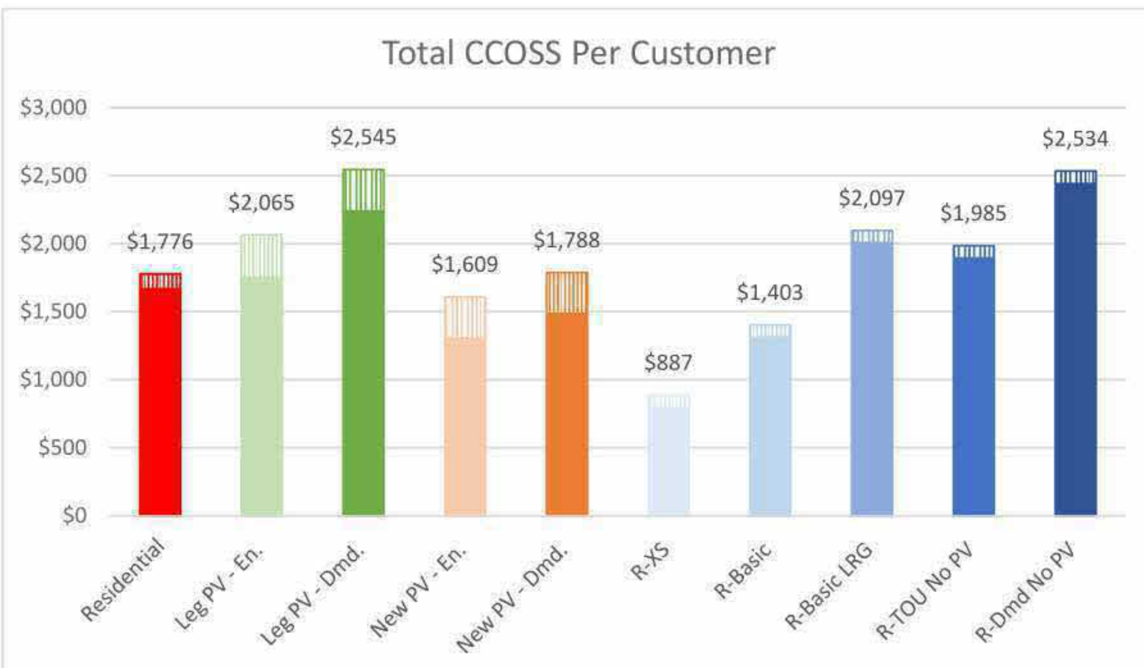


Figure 6 - Total CCOSS Per Customer

Q89. IS THERE ANOTHER WAY TO COMPARE THE COST TO SERVE SOLAR CUSTOMERS WITH THE COST TO SERVE NON-SOLAR CUSTOMERS?

A89. Yes. Another way to highlight this difference is by looking at the non-metering costs on their own against the subclass's delivered energy requirements. The additional production meters are not required for billing purposes and provide no specific value to customers. While the Company in the past may have relied on the production meter data to comply with its Renewable Energy Standard and Tariff ("REST") obligations, it currently obtains waivers from the Commission.[55] Figure 7 compares the non-metering costs for each residential subgroup, highlighting the general parity between the solar and non-solar classes for the production, transmission, distribution, and energy components of the cost of service.

Figure 7 - Non-Meter Costs per kWh

Q90. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FROM THIS SECTION OF YOUR TESTIMONY.

A90. I recommend the Commission require the following changes to the Company's CCOSS methodology:

- Utilize more modern cost allocation approaches such as those recommended by the RAP Manual that are better suited to the operation of modern utilities.
- Provide more detail in how load shapes are calculated from billing information, including more information about demand and energy adjustments.
- Recombine solar customers with non-solar customers in the CCOSS and rate design process.

[55] Attachment KL-24, SEIA 31.1

- Use delivered energy rather than site energy for solar customers.
- Remove the "solar credit" concept from the CCOSS.
- Properly adhere to the Commission's requirement that the CCOSS workpapers be transparent, accessible, and flexible as directed in Decision 75859.
- Properly adhere to the Commission's requirement that residential subclass Class NCP values are calculated based on the same hour as the combined total residential Class NCP as directed in Decision 76900.
- Develop a more robust method to account for customer growth over the test year in the CCOSS.
- Investigate ways to reduce metering costs for solar customers.

III. <u>THE COMPANY'S PEAK HOURS ARE NOT OPTIMALLY ALIGNED WITH SYSTEM AND CLASS LOAD</u>

Q91. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A91. In this section, I discuss the Company's current rate design for its universally-available R-TOU-E, R-2, and R-3 tariffs. I begin by analyzing the Company's system and residential class loads over the past four years to identify trends that inform the rate design process. After this, I discuss an alternative rate design that will better align rates with system loads and offer customers more accurate price signals.

Q92. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A92. I find that the Company's current choice of seasonal months and peak hours are inconsistent with the actual load conditions that drive costs. There is no analytical justification for a year-round peak period, and little basis to include the shoulder months of May and October in the "summer" season. I also find that the current peak hours of 3 PM to 8 PM are not optimally aligned with system and class load conditions, resulting in price signals that are weaker than necessary.

After this discussion, I propose an alternative rate design to replace the Company's flagging R-TECH rate that is designed to facilitate users to control their loads, generation, and storage systems in a manner that works to reduce their individual bills and overall system costs. This rate features a June to September summer period with a 2 PM to 7 PM peak period, no Grid Access Charge, and a higher summer on-peak rate. Together, this optional rate will better support active management of load to reduce costs for all of the Company's customers.

The Company's Peak Hours are Not Optimally Aligned with System and Class Loads

Q93. WHAT ARE THE PEAK HOURS FOR THE COMPANY'S CURRENTLY-AVAILABLE TIME DIFFERENTIATED RATES FOR RESIDENTIAL CUSTOMERS?

A93. While the Company's legacy rates had peak periods of 9 AM to 9 PM or 12 PM to 7 PM, its current R-TOU-E, R-2, and R-3 rates have a peak period of 3 PM to 8 PM on non-holiday weekdays. These peak hours are used for both billing energy and demand. Although the Company has shortened the duration of the peak period over the years, the Company's use of year-round demand charges does not send meaningful price signals outside of the core summer months.

Q94. WHY IS THIS THE CASE?

A94. It is because the Company's system is built to handle peak loads which disproportionately occur during July and August. Figure 8 below shows the average load profile for each month for the years 2016-2019. As is clearly visible, the Company does not have two seasons a year. The peak demand occurs during the two core summer months of July and August. June and September still produce high peaks, but the average peak load is nearly 800 MW lower than the core summer months. Outside these four months, peak demand falls dramatically. Shoulder months in green (March – May and October – November) are milder and see flat load with a modest afternoon peak and no morning peak. The core winter months of December to February in blue are distinguished by a morning peak and a smaller evening peak. Regardless, the absolute demand levels in the shoulder and winter months are well below the summer system peak values. Clearly, if APS has sufficient capacity to serve its summer loads, it has more than enough to serve winter and shoulder loads.

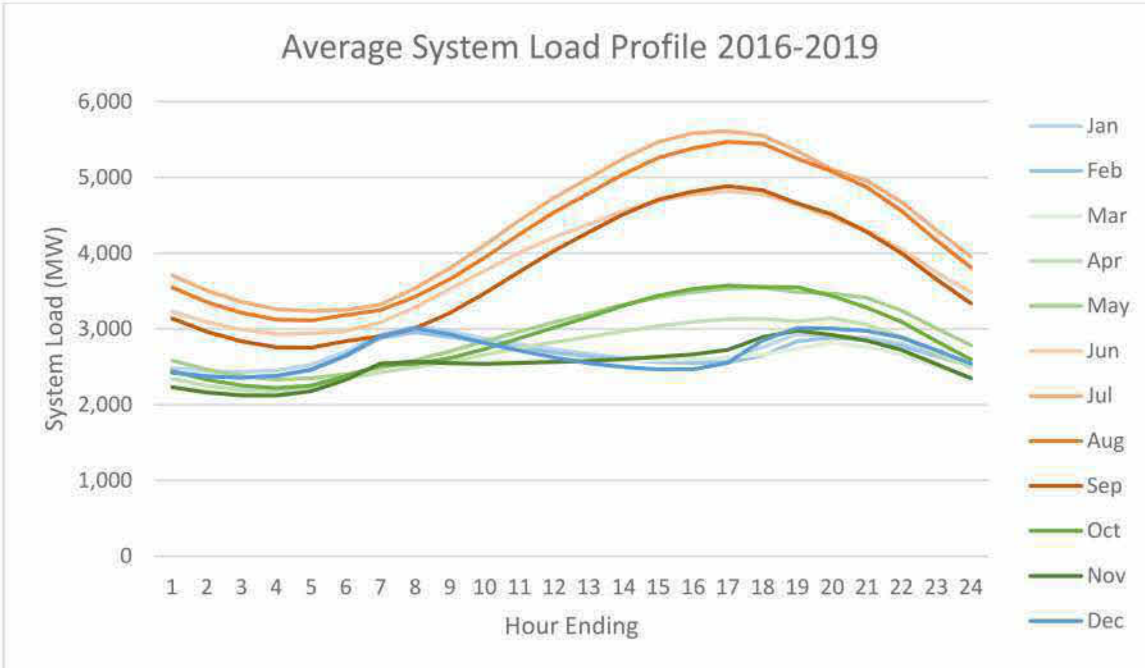


Figure 8 - Average System Load Profile 2016-2019

Figure 9 below focused on the peak load hours and shows the top 500 system load hours from 2016 through 2019. Exactly zero of these peak hours occur outside of the core summer months of June to September, and 81% occurred during July and August. Notably, the hours between 2 PM and 7 PM (HE 15 to HE 19) contain a higher percentage of peak system hours (85.4%) than the Company's current peak hours of 3 PM to 8 PM (75.2%).

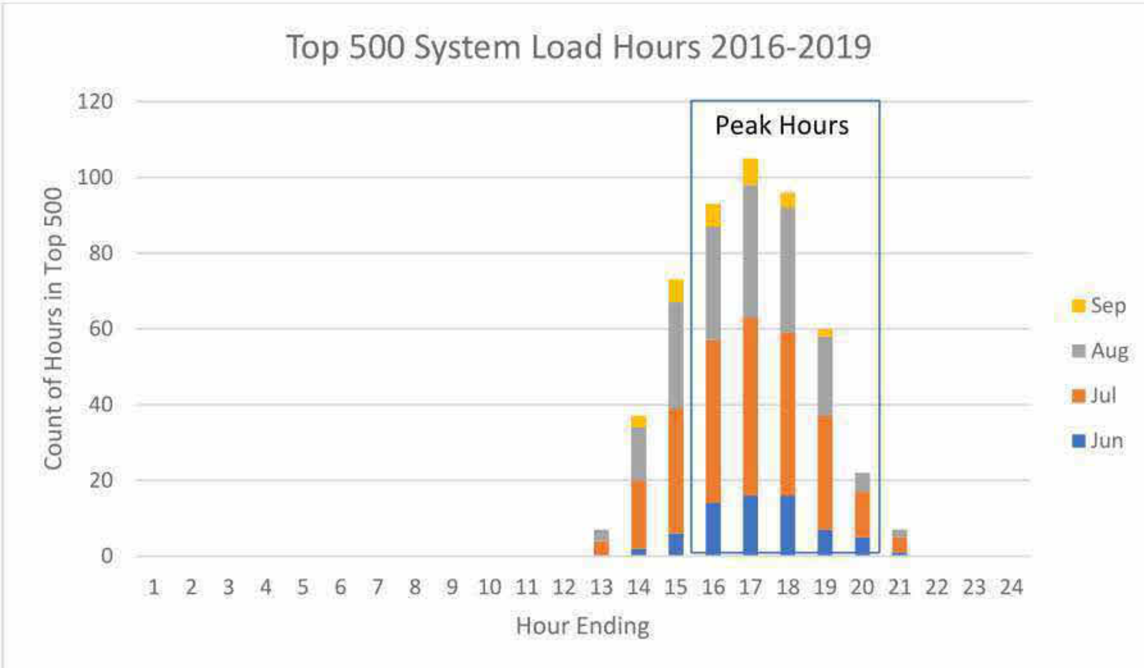


Figure 9 - Top 500 System Load Hours 2016-2019

Q95. DID YOU ALSO ANALYZE THE TRENDS IN THE RESIDENTIAL CLASS LOAD?

A95. I did. The residential class tends to peak slightly later than the system peak, but otherwise shows remarkable similarity to the system peak over the months. The same three grouping of months are present as with the system load as seen in Figure 10 below.

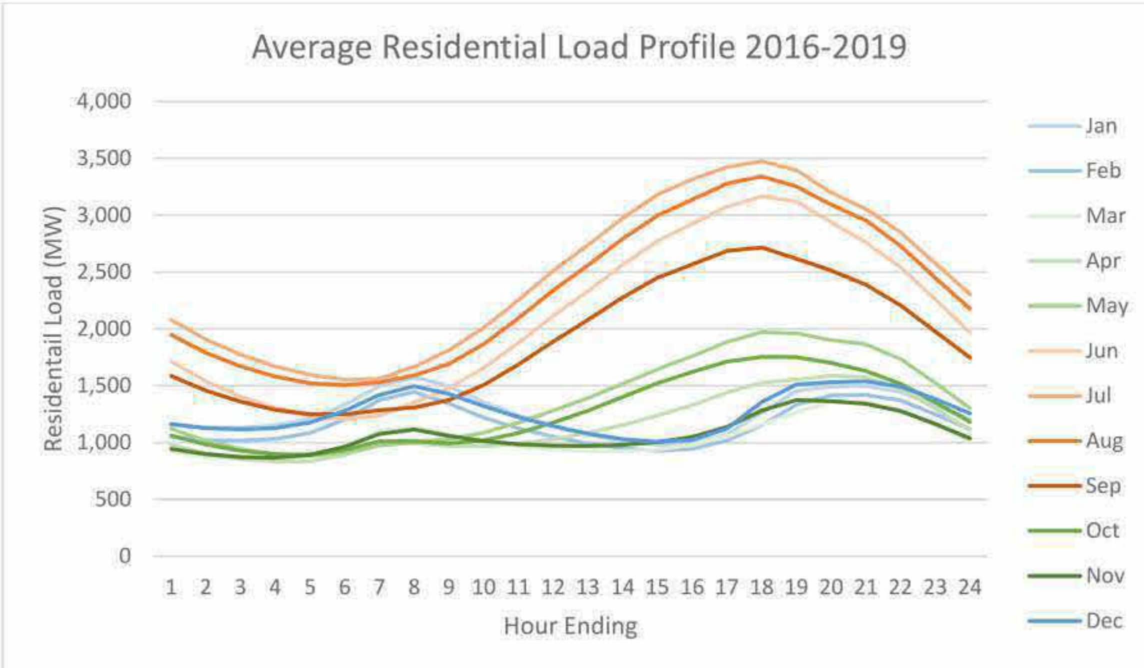


Figure 10 - Average Residential Load Profile 2016-2019

Likewise, the top 500 hour analysis show in Figure 11 below has the same shape in terms of core summer months being responsible for peaks, although there are slightly more peak hours that fall in the 7 PM to 8 PM range than for the system peak.

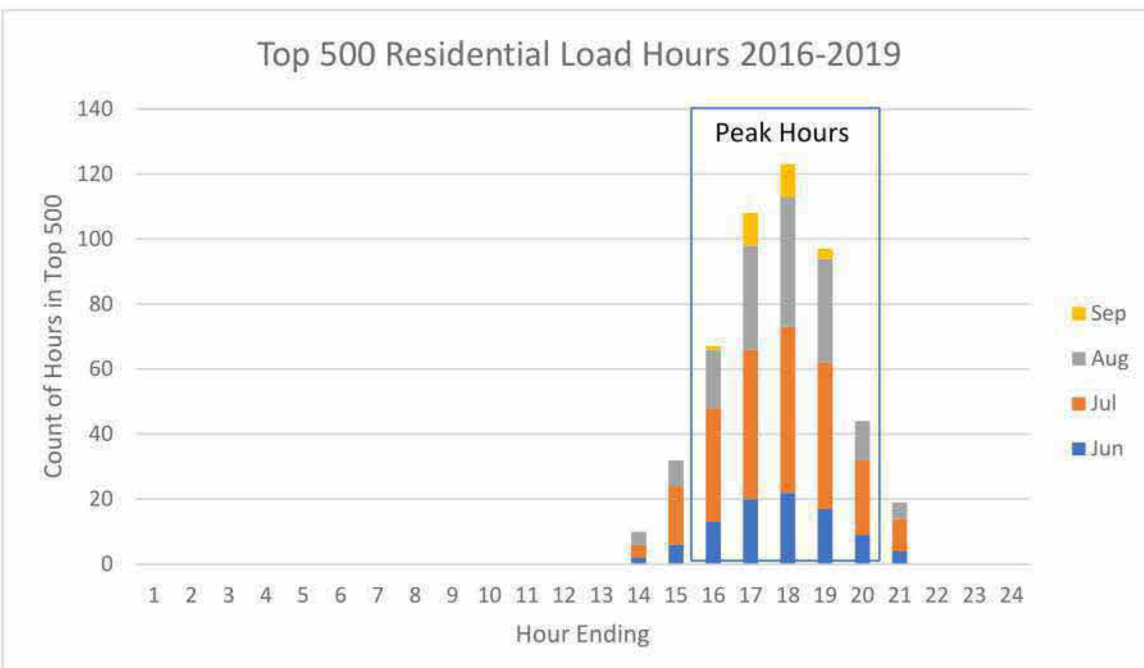


Figure 11 - Top 500 Residential Load Hours 2016-2019

Q96. WHAT DOES THE FIGURE ABOVE MEAN FOR DEMAND-BASED CHARGES THAT RECOVER GENERATION CAPACITY COSTS?

A96. It means that the Company's demand charges for generation are not well aligned with cost-causation. As a first matter, based on the system load over the past four years, there are no generation capacity costs that are driven by winter loads. The highest load in the past four years in the "winter" months was the 5,100th hour and had a load of 4,309 MW. This is only 62% of and nearly 2,700 MW lower than the peak demand of 6,995 MW. The "winter" loads are simply not driving the Company's peak demand needs.

While the R-3 tariff does have a higher generation demand charge in the summer than in the winter, the R-2 rate does not. Customers on the R-2 rate are told through their rates that a demand reduction at 5 PM in July is just as valuable to the system as a demand reduction at 8 PM in April. Clearly this is not the case, and as such, demand charges during winter months are not sending meaningful prices signals to customers as there is no generation capacity benefit of reducing demand during this time.

Q97. DOES THE SAME HOLD TRUE FOR DEMAND-BASED CHARGES THAT RECOVER DISTRIBUTION COSTS?

A97. The case is not as clear for distribution costs, which are allocated based on the residential class peak for primary distribution assets and on the sum of individual customer maximum demand for secondary distribution assets. The residential class has peaked between 5 PM and 6 PM in each year between 2016 and 2019, suggesting that primary distribution costs are well aligned with the overall system peak. As with generation demand, there is no incremental distribution demand need in the winter and shoulder months that cannot already be served by the distribution system built for the summer peak. That said, it may be the case that some secondary distribution system elements peak during winter hours, particularly for feeders serving many customers with electric heating.

However, both the R-2 and R-3 tariffs charge a constant demand rate of $4.09 / kW for billing demand during peak hours throughout the year. Maintain a constant distribution demand charge across all months clearly over-recovers costs during winter months and under-recovers costs during summer months compared to costs driven by distribution demand.

Q98. HAVE THESE PEAK HOURS SHIFTED OVER TIME?

A98. Not really. Figures 12 and 13 below show the number of top 100 load hours from each year that fall into any given hour period along with the average peak time of the year.[56] The system peak hours were very stable between 2016 and 2018, varying less than 6 minutes. There was a shift towards an earlier peak in 2019, with the weighted average hour moving forward to 3:54 PM. The residential system was more stable over the years, with peaks falling between 5:04 PM and 5:19 PM in each of the years.

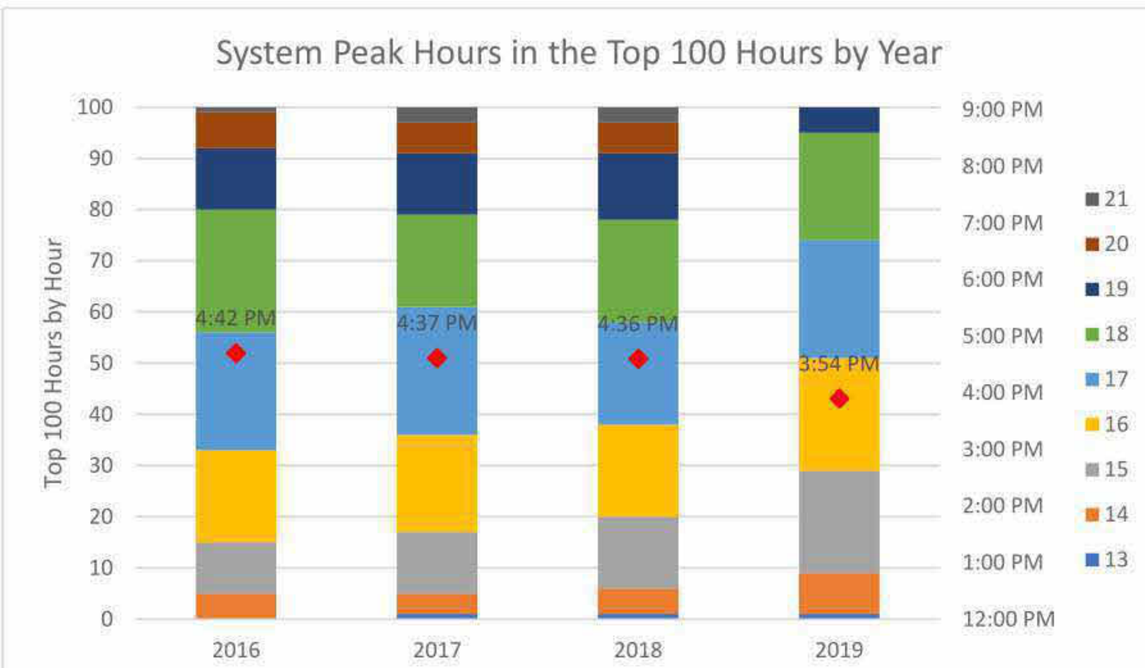


Figure 12 - Top 100 System Load Hours by Year

[56] The times here represent the average of the peak hour weighted by hour of the day A peak hour was assigned a value on the half hour, so a top 100 hour that fell between 1 PM and 2 PM was weighed with a value of 1:30 PM.

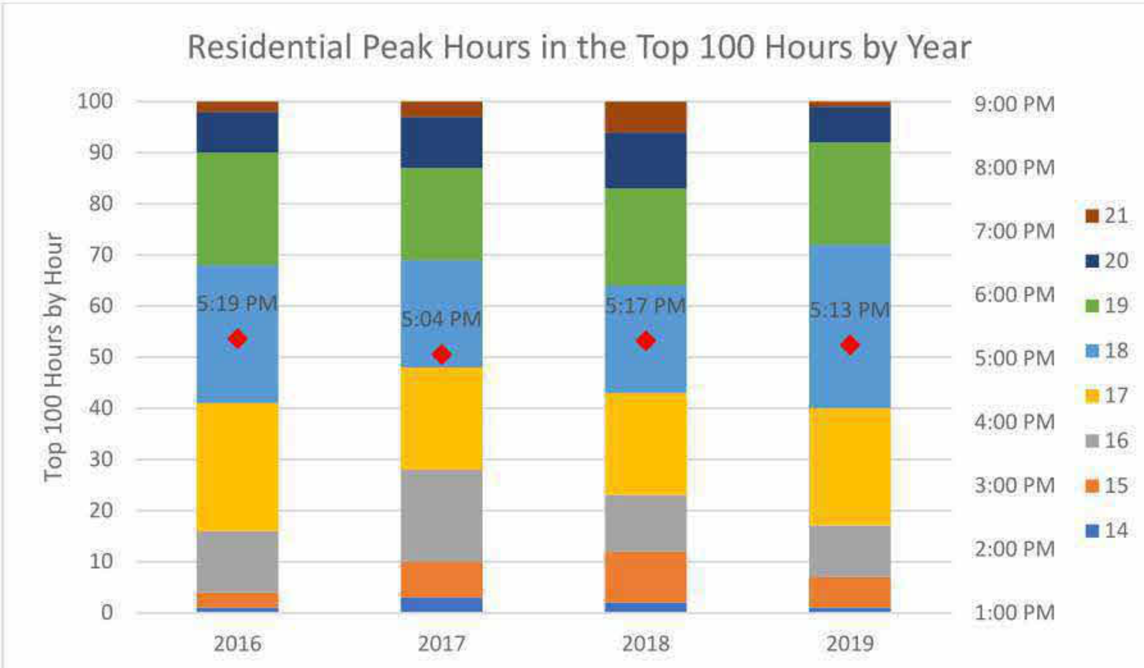


Figure 13 - Top 100 Residential Load Hours by Year

Q99. DOES THE COMPANY APPEAR TO BE TARGETING THE OPTIMAL MONTHS AND HOURS IN ITS R-TOU-E, R-2, AND R-3 RATES?

A99. No, it does not appear to be targeting the optimal months or hours. There appears to be little basis for a year-round peak period, much less one with equal or nearly equal rates between winter and summer. The Company's R-TOU-E proposed peak winter energy rate is \$0.23552 / kWh, not even two cents less than its proposed summer peak rate of \$0.24823 / kWh. The R-2 rate has the same demand charge year-round, with a similarly small 2.3 cents / kWh spread between summer and winter peak rates. There also does not appear to be justification for a six-month "summer" given the low load conditions of May and October.

Figure 9 above shows that the top 500 system load hours show that the most appropriate four-hour peak is between 2 PM and 6 PM and the most appropriate five-hour peak between 2 PM and 7PM. It is also clear from this figure that the hour between 2 PM and 3 PM contains more peak hours than the hour between 7 PM and 8 PM. The case is not as clear for primary system distribution costs, which are allocated based on class peak. The peak hours of 3 PM and 8 PM are better aligned with the residential class distribution peak than with the system peak hour but shifting to 2 PM to 7 PM would still capture over 85% of the peak hours in the past four years.

The hours have not shifted notably over time either. Had there been a trend towards later peaks in either the system load or the residential load, then maintaining the current 3 PM to 8 PM may be warranted. But it appears that the hours of 2 PM to 7 PM do a better job targeting both system load and residential load.

Q100. BUT IF THE COMPANY SHIFTED TO A FOUR-MONTH SUMMER PEAK PERIOD, WOULD ITS ON-PEAK RATES INCREASE SUBSTANTIALLY?

A100. Not necessarily. The Company has much latitude in developing revenue-neutral rates that can reflect a balance between summer and winter, peak and off-peak, and demand and energy rates. The Company should be able to develop a rate that more properly reflects the summer-peaking nature of its system without making summer on-peak energy rates excessive.

Q101. WHAT DO YOU RECOMMEND REGARDING THIS ISSUE?

A101. Both the system and class peaks are dominated by summer loads. Further, the summer loads are only significant in the core months between June and September. Setting peak hours between 3 PM and 8 PM year-round produces rates that do not send meaningful price signals for 8 months a year. I recommend the Commission reconsider the appropriate time and duration of peak hours that are affecting customers today and require the Company to refile its R-2, R-3, and R-TOU-E residential rate designs with a 2 PM to 7 PM peak from June to September that better reflect the cost drivers on APS's system. If evolving data unequivocally demonstrates that this time period no longer reflects the most balanced set of hours for residential customers (taking into account factors such as customers usage, solar penetration, customer acceptance, and equity issues), the Commission can make adjustments at a future time.

SEIA's Alternative R-TECH Rate Design Proposal is Better Aligned with Costs and Loads

Q102. WHAT IS THE R-TECH TARIFF?

A102. The R-TECH tariff is a pilot rate that is designed to "test the ability and desire of participating residential Customers to reduce On-Peak energy and demand usage through multiple behind-the-meter technologies."[57] To qualify for the rate, customers must have two or more qualifying "primary" technologies or one qualifying primary technology and two qualifying "secondary" technologies. The list of primary and secondary technologies is found in Table 6 below. The tariff was approved in August 2017 and was initially limited to 10,000 customers.

Primary Qualifying Technology	Secondary Qualifying Technology
Rooftop PV system > 2 kW_{DC}	Device with variable speed motor (pool pump, HVAC)
Chemical storage system > 4 kWh	Grid-interactive water heating system
Electric vehicle	Smart thermostat
	Automated load controller

Table 6 - R-TECH Tariff Qualifying Technologies

Q103. HOW MANY SOLAR AND NON-SOLAR CUSTOMERS TOOK SERVICE ON THIS TARIFF DURING THE TEST YEAR.

A103. The Company had two solar customers on the tariff at the beginning of the test year and 14 at the end of the test year. The average number of solar customers taking service over the test year was five. There were an additional 8 and 16 non-solar customers taking service on this at the beginning and end of the test year, respectively. All told, the test year ended with only 29 customers being served on the R-TECH tariff.[58]

Q104. HOW MANY CUSTOMERS IN APS'S TERRITORY HAVE INSTALLED SOLAR PLUS STORAGE SYSTEMS?

A104. According to data from Arizona Goes Solar, APS has interconnected 694 solar plus storage systems for a total of nearly 5.5 MW of solar capacity.[59] While these customers clearly

[57] Rate Schedule R-TECH.
[58] Initial 1.31_ExcelAPS19RC00282_2018 2019 Load Research Report
[59] https://arizonagoessolar.org/aps/. Accessed July 24, 2020. Data for Residential "Solar Plus Battery" systems that had a non-blank Installation Date value.

represent a minority of those that have installed solar, that only 14 chose the R-TECH tariff at the end of the test year suggests the rate is not attractive for solar plus storage customers.

Q105. HOW MANY CUSTOMERS IN APS'S TERRITORY HAVE ELECTRIC VEHICLES?

A105. The most recent annual report for the EV-Ready program suggested that there were at least 3,700 EVs in APS's territory as of April 2017.[60] A more recent EPRI study suggests there are approximately 16,500 EVs in APS's territory.[61] Again, that almost all EV owners choose to be served on other tariffs speaks to the deficiencies of the current R-TECH rate design.

Q106. DOES THE COMPANY HAVE ANY IDEAS WHY THE PARTICIPATION ON THIS RATE HAS BEEN SO LOW?

A106. APS states the while the reasons are "not definitively known at this time, the low participation to date could have several causes including the attractiveness of Rate Schedule TOU-E to solar customers, low adoption of residential battery storage, or the requirement to purchase new technologies, among other potential reasons."[62] Regardless of the reasons, it is clear that the current structure of the R-TECH rate is not meeting the policy objectives of the tariff.

Q107. WHAT ARE THE BENEFITS OF RESIDENTIAL SOLAR PLUS STORAGE SYSTEMS?

A107. In many ways, pairing solar and storage is the next evolution of residential installations. In areas with low solar penetration, there continues to be substantial value in adding more standalone solar systems. These system help reduce CO_2 emissions, reduce peak demand, and can delay or defer large-scale, high-cost grid investments.

Maturing solar markets such as Hawaii, California, and increasingly Arizona are beginning to transition from standalone solar to solar plus storage installations. By pairing these resources, the myriad benefits of distributed solar can be maintained and enhanced. The addition of storage allows a solar plus storage system to continue to reduce net load (e.g.

---

[60] APS ev-READY Study Annual Report May 2017. Available at https://docket.images.azcc.gov/0000179400.pdf?i=1578426322394

[61] Attachment KL-25, Staff 14.15.

[62] Attachment KL-26, SEIA 5.5d.

load remaining after wind and solar is netted) later in the afternoon. It also reduces solar overgeneration in the middle of the day, which can lead to curtailment during mild shoulder seasons. Batteries also can transform residential customers from mere consumers of energy to active participants on the grid, supplying valuable grid services while providing their owners with a local source of backup power should the broader grid go down.

Rate design can be a critical enabler – or detractor – of this shift. By creating well formulated rates that enable customers to discharge their battery storage systems during peak hours, APS can tap the potential of residential customers to do more than just reduce their usage during peak hours, but instead actively provide power to support the grid during times of high load. The R-TECH tariff was intended to support this type of behavior, but unfortunately, its design is standing in the way.

Q108. WHAT IS THE STRUCTURE OF THE R-TECH TARIFF?

A108. The R-TECH tariff is a complicated rate with high demand charges and low energy charges. Peak hours are between 3 PM and 8 PM weekdays, with Summer months running from May to October. Table 7 below shows the key characteristics for the tariff.

Category	Summer	Winter
BSC ($/Day)	$0.505	$0.505
Demand ($/kW)		
Peak	$20.653	$14.540
Off-Peak		
First 5 kW	$0.00	$0.00
All Remaining	$6.642	$6.642
Energy ($/kWh)		
Peak	$0.05888	$0.04869
Off-Peak	$0.04869	$0.04869

Table 7 - R-TECH Tariff Details

Q109. HOW DOES THIS STRUCTURE DIFFER FROM THE OTHER DEMAND-BASED RATES, R-2 AND R-3?

A109. The rates share the same peak hours and seasons, but otherwise are quite different. Both the R-2 and R-3 have a proposed super off-peak period with very low energy charges. Neither have off-peak demand charges. The R-2 has much lower demand charges ($8.688 / kW) and a higher spread between on-peak and off-peak energy rates. The R-3 has somewhat lower demand charges ($17.960 and $12.594 / kW in the summer and winter, respectively), and a higher spread between on-peak and off-peak energy rates.

Q110. THE R-TECH'S OFF-PEAK DEMAND CHARGE OFFERS THE FIRST 5 KW FOR FREE BEFORE CHARGING. IS THE OFF-PEAK DEMAND OF MOST CUSTOMERS LIMITED TO 5 KW?

A110. No. Customers on this tariff had a total of 996 kW that fell into the free tier, and 1,365 kW that were charged at the higher rate.[63] While the free tier did provide a discount on off-peak demand charges for many customers, the customers were still charged for a significant amount of off-peak demand usage.

Q111. WHAT IS THE POINT IN CHARGING CUSTOMERS FOR THEIR NON-COINCIDENT PEAK DEMAND USED DURING OFF-PEAK PERIODS?

A111. There is little purpose to residential non-coincident peak demand charges as they do not encourage peak reduction during times when the system is experiencing high load. Residential customers have high load diversity, and distribution equipment serving residential customers is sized to take advantage of this. The R-TECH off-peak demand charge is designed to primarily recover delivery costs, but this non-coincident charge does not send meaningful signals to customers.

The R-TECH rate is supposed to encourage customers to shift usage out of peak times into off-peak times. Suppose a customer with an electric vehicle does this, configuring her car to charge between 1 AM and 5 AM when the distribution and bulk power system have spare capacity, even during the hot summer months. Many Tier 2 residential charges are able to pull 9.6 kW of power, although some models can charge twice as fast, using 19.2 kW of power.[64] A customer charging their vehicle overnight will still trigger a sizable

[63] JEH-WP1DR Proof of Revenue.
[64] A 240 volt/40 amp charger has a maximum draw of 9.6 kW, while an 80 amp model can pull 19.2 kW.

demand charge, despite the rate supposedly providing an incentive to switch usage to this time.

Q112. HOW DOES ENERGY AND DEMAND REVENUE COLLECTION DIFFER ON THE R-TECH FROM THE R-2 AND R-3 TARIFF?

A112. The R-TECH collects far more revenue through demand charges than the other tariff, and in facts collects more through demand charges than most commercial rates. Figure 14 below shows the collection for the various residential and selected commercial tariffs. 58% of R-TECH revenue is collected through the demand charge, compared to 45% on the R-3 and 27% on the R-2 tariff. The commercial rates tilted most strongly towards demand collect just under half of revenue through demand charges.[65]

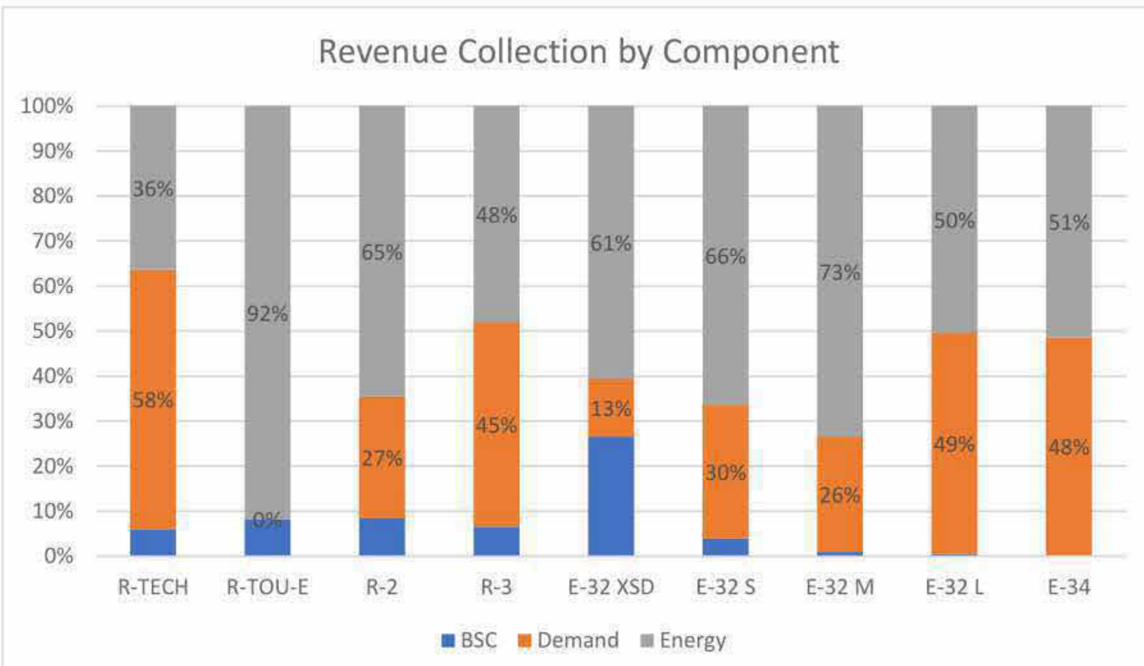


Figure 14 - Revenue Collection by Component

Put another way, nearly 60% of the customer's monthly bill will be determined from at most two hours of usage per month. Once these demand levels are locked in, there is almost no incentive to continue to reduce peak demand or energy usage for the remainder of the month. The energy rates are very low, and the differential between peak and off-peak

[65] JEH-WP1DR Proof of Revenue

energy is only $0.01 / kWh in the summer and is in fact $0.00 / kWh in the winter. These are not price signals that encourage energy shifting once the monthly peak demand has been set.

Q113. HOW CAN THE R-TECH TARIFF BE IMPROVED TO BETTER SUPPORT THE ABILITY AND DESIRE OF PARTICIPATING RESIDENTIAL CUSTOMERS TO REDUCE ON-PEAK ENERGY AND DEMAND USAGE THROUGH MULTIPLE BEHIND-THE-METER TECHNOLOGIES?

A113. The rate should be changed to target energy and demand reductions during months and hours when they are most useful to all customers and do so through a mechanism that is easier for customers to understand and respond to. SEIA's proposed R-TECH alternative is a volumetric TOU rate that uses a shorter summer season, an earlier peak period, and a super off-peak period. It does not have a Grid Access Charge and has slightly higher rate differentials than the R-TOU-E rate. These changes present stronger incentives for customers to reduce on-peak demand and are shown in Table 8 below.

	SEIA R-TECH Alt.	R-TOU-E
Summer Months	June – Sept	May – Oct
Peak Hours	2 – 7 PM Weekdays	3 – 8 PM Weekdays
Super Off-Peak Hours	10 AM – 2 PM Weekdays, Year-Round	10 AM – 3 PM Weekdays, Non-Summer
BSC ($/Day)	$0.437	$0.437
Summer Energy ($/kWh)		
Peak	$0.28550	$0.24823
Off-Peak	$0.11420	$0.11122
Super Off-Peak	$0.04941	N/A
Non-Summer Energy ($/kWh)		
Peak	$0.22840	$0.23552
Off-Peak	$0.11420	$0.11122
Super Off-Peak	$0.04941	$0.03294
Grid Access Charge	None	$0.951 / kW_{DC}

Table 8 - SEIA R-TECH Alternative Proposal vs. R-TOU-E

Q114. PLEASE DESCRIBE HOW THE RATES ABOVE WERE PRODUCED.

A114. The hours and seasons are based on the analysis of the Company's residential and system loads. I extended the super off-peak period year-round, increasing the summer rate by 50% over the non-summer rate. I set the summer peak / off-peak ratio at 2.5 : 1 and the non-summer peak / off-peak ratio at 2 : 1. With this structure, I calculated the rates that were revenue neutral with respect to the R-TOU-E rate using the billing determinants from my modified per capita load profile discussed in Section II above.

The result is a higher peak rate in the summer months, a slightly lower peak rate in the non-summer months, and a very similar off-peak rate. The rate provides a meaningful price signal to reduce peak energy during summer afternoon when the system is under the highest load. It lessens the price differential during non-summer months to reflect the lower, but non-zero, usefulness of reducing load during non-summer months. It maintains the super off-peak period to reflect the very low marginal cost of energy during midday hours when solar's share of generation is rising.

Q115. THE COMPANY CLAIMS THAT TIME OF USE RATES "DO NOT INCENT THE CONSISTENT REDUCTION IN PEAK USAGE THROUGHOUT THE MONTH, AS DO DEMAND RATES, THAT IS REQUIRED TO EFFECTIVELY REDUCE DEMAND-RELATED COSTS."[66] ARE YOU CONCERNED THAT BY NOT HAVING A DEMAND CHARGE THAT CUSTOMERS WILL NOT BE SUFFICIENTLY INCENTED TO REDUCE THEIR ON-PEAK DEMAND AND ENERGY USAGE?

A115. No. Volumetric time of use rates provide an incentive in every peak hour of every month to reduce demand, because reducing demand lowers energy usage, which in turn produces lower bills. There is a stronger incentive to reduce on-peak energy use under the SEIA proposal than under either the R-TECH or the R-TOU-E tariff. This in turn produces an incentive to reduce demand, as energy is simply a measure of demand sustained over time. By contrast, once a customer has set their peak demand in a given month under the current R-TECH tariff, there is no incentive to reduce demand further (as the billing demand is locked in) and very little incentive to reduce energy usage further (as the volumetric rates and portion of the bill are low).

[66] Attachment KL-27, SEIA 19.1.

I also disagree with the Company's premise that consistent demand reductions are required throughout the month "to effectively reduce demand-related costs". The Company's on-peak period covering the hours from 3 PM to 8 PM weekdays during half of the year results in 1,300 peak hours during the test year, or nearly 15% of the total hours. However, the bulk of demand costs are driven by a just a handful of these peak hours. Suggesting that the only effective way to reduce demand-related costs requires customers to actively monitor and consistently reduce demand during roughly one out of every six hours over the entire year is simply inconsistent with the actual cost drivers on the system.

Q116. WILL THIS PROPOSED RATE DISPROPORTIONATELY BENEFIT SOLAR CUSTOMERS?

A116. No. As a first matter, customers who have solar systems but do not also have two secondary technologies are not eligible for this rate. For solar customers who qualify, the benefit of this rate over the R-TOU-E is small. When the generation profile of all solar customers is overlaid against the SEIA R-TECH alternative proposal, the value of solar generation is only 2.8% higher than on the R-TOU-E rate. This incremental value could be eliminated by setting the summer super off-peak value equal to the non-summer off-peak value. In this case, savings that can be realized from this tariff will be driven be the underlying load changes of the customer and not the mere presence of solar.

Q117. WILL THIS PROPOSED RATE ONLY BENEFIT CUSTOMERS WITH SOLAR AND STORAGE?

A117. No. While the high energy rate differentials will incent solar plus storage customers to discharge energy storage systems during peak periods, it also will provide incentives for non-solar customers to also reduce their peak energy and demand. Customers with electric vehicles can charge during the off-peak or super off-peak periods without worrying about triggering a punitive off-peak demand charge. Variable speed motors on pool pumps and grid-interactive water heaters can be programmed to operate during non-peak times. Customers with smart thermostats can pre-cool houses during the super off-peak period, reducing their need for air conditioning during peak hours. All of these actions are supported through the SEIA R-TECH alternative proposal.

IV. THE COMMISSION SHOULD PAUSE THE RCP STEPDOWN AND EXTEND ITS LOCK-IN DURATION

Q118. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A118. In this section, I discuss the current state of the RCP rider and its role in supporting the adoption of rooftop solar in the Company's territory. I discuss how the RCP rider should be frozen at its current level given the slowdown in installations since its inception and its questionable and controversial origin as part of the flawed Value of Solar docket.

Q119. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A119. The Arizona Goes Solar data shows a considerable drop from its previous trajectory of installations. Allowing the RCP to continue to step down will likely perpetuate this trend. To counter this, I recommend the Commission permanently extend its recent freeze of the RCP at its current level. I also recommend that it extend the lock-in period from ten years to at least 18 years to match the term provided to PURPA qualifying facilities and to better match the long term certainty the utility is permitted for its own resource investments.

Q120. WHAT IS THE RCP?

A120. The RCP is a rider that is part of the net billing structure that has replaced net energy metering ("NEM") for residential customers in Arizona. Rather than NEM's accounting for surplus generation (i.e. solar production in excess of customer consumption) from month-to-month through kWh carryforwards, net billing converts any surplus generation into a bill credit. APS implements net billing on an instantaneous basis; that is, all energy that flows from the grid to the customer is charged at the full retail rate, while all energy that flows from the customer to the grid is credited at the RCP rate.

The RCP rate is reset on an annual basis and cannot decrease more than 10% per year. A customer is assigned a tranche based on the date of their interconnection application, provided that they subsequently complete their installation within 180 days. Customers retain the RCP based on their tranche for 10 years, after which time exported energy is purchased at the then-applicable rate. Table 9 shows the current and projected RCP values, with an assumption that the program stabilizes around the 9/1 to 8/31 dates.

Tranche	Eligible Application Date	Value ($ / kWh)
Tranche 2017	9/1/17 to 9/30/18	$0.12900
Tranche 2018	10/1/18 to 9/30/19	$0.11610
Tranche 2019	10/1/19 to 8/31/20	$0.10450
Tranche 2020	9/1/20 to 8/31/21	$0.09405
Tranche 2021	9/1/21 to 8/31/22	$0.08465
Tranche 2022	9/1/22 to 8/31/23	$0.07618
Tranche 2023	9/1/23 to 8/31/24	$0.06856

Table 9 - RCP Stepdown Schedule

The RCP was initiated as a result of a controversial decision in the Commission's Value of Solar Docket.[67] That decision was the subject of an appeal that was never heard by the courts because it was dropped as part of the settlement of the last APS rate case.[68] At this time, the RCP construct has never been turned into a rule and, in fact, directly conflicts with the Commission's adopted Net Metering Rules.[69]Given the controversy around that decision, the fact that the RCP continues to conflict with Commission Rules, and its negative impact on solar adoption, economic development, clean energy generation, and jobs, I believe it is critical for this Commission to carefully examine if the continued step-down of the RCP and its brief lock in term is appropriate.

Q121. HOW DOES THE RCP COMPARE TO THE AVERAGE PRICE OF RESIDENTIAL RATES?

A121. The RCP is substantially lower than the average residential rate. Under the Company's current base rates, the average all-in rate is $0.13301/kWh. To attain the Company's proposed revenue net of adjustor transfers, each kWh of energy sold to the residential class must collect $0.1402.[70] These figures do not include other rate riders, which push the

---

[67] *See* Decision 75859.
[68] *See* Section XXXV of Settlement Agreement to last APS Rate Case (Exhibit A to Decision 76295).
[69] *See e.g*. R14-2-2306(D) ("If the electricity generated by the Net Metering Customer exceeds the electricity supplied by the Electric Utility in the billing period, the Customer *shall be credited during the next billing period for the excess kWh generated.* That is, the excess kWh during the billing period will be used to reduce the kWh supplied (not kW or kVA demand or customer charges) and billed by the Electric Utility during the following billing period") (emphasis added).
[70] JEH-WP1DR Proof of Revenue.

effective retail rate even higher. As it currently stands, the RCP is 25% lower than the average rate under the Company's proposed revenue and would fall to 33% lower at the next scheduled step down.

Q122. DOES THE RCP CREDIT APPLY TO ALL GENERATED ENERGY OR JUST EXPORTED ENERGY?

A122. It applies only to exported energy. The customer remains free to consume the solar generation on site and thereby avoid buying electricity from the utility. However, for working families that cannot time their electricity consumption with their solar generation on an instantaneous basis, this arrangement has the effect of disadvantaging working people who are not home during the day.

Q123. ON AVERAGE, HOW MUCH SOLAR PRODUCTION IS EXPORTED VS. SELF-CONSUMED?

A123. While individual customers will show variations in this metric, on average about 57% of solar production in the test year was exported and 43% self-consumed. Table 10 below shows the ratios for the various solar subclasses. These values may change from year to year as the weather – and corresponding customer load – changes. Given the relatively high level of exports, the magnitude of the RCP rate is clearly consequential to solar customer economics. Its value affects customer's ability to save on monthly utility bills and allowing the RCP to fall further will likely have detrimental impacts on the economic viability of Arizona's clean energy workforce going forward.

	Exported	Self-Consumed
E_12_Solar	60.77%	39.23%
ECT_Solar	51.35%	48.65%
ET_Solar	53.57%	46.43%
R_2_Solar	64.44%	35.56%
R_3_Solar	62.17%	37.83%
R_TOU_E_Solar	64.49%	35.51%
All Solar	**57.30%**	**42.70%**

Table 10 - Export vs. Self-Consumed Solar Generation

Q124. WHAT PARAMETERS DICTATE HOW MUCH SOLAR PRODUCTION IS EXPORTED COMPARED TO CONSUMED ON SITE?

A124. The ratio of generation that is exported depends on several factors. First, it depends on how coincident the customer's load is with generation. A customer that uses more energy in the middle of the day will self-consume a higher fraction of their production than one who uses energy late at night or early in the morning. Second, it depends on the system size relative to the annual usage of the customer. Systems that are sized to cover a larger fraction of a customer's total annual energy consumption will export more energy relative to a system that is sized to cover a smaller fraction of their energy use. Finally, it depends on the time over which the Company calculates imports and exports. Longer periods of time (e.g. monthly netting) will result in less exported energy than shorter periods. The Company's implementation of instantaneous netting represents the extreme end of this calculation and contributes to the relatively high levels of exported energy shown above. Instantaneous netting also complicates and obscures the value of solar adoption because most residential ratepayers are not aware of how much energy they are using at any time of the day, and even if they were aware, would may not be able to sufficiently change their behavior during normal working hours.

Q125. WHAT HAPPENS TO EXPORTED ENERGY?

A125. It flows to the nearest load, where it is consumed. Unless there is particularly high penetration of solar on a given feeder, this means it most likely will flow from the solar customer's meter to the nearest line transformer to the nearest neighbor, where it will be consumed and billed by the Company at the full retail rate. Under the Company's proposed R-TOU-E tariff, this neighbor would pay $0.24823 / kWh during summer peak hours and $0.23552/kWh during winter peak hours. By comparison, the current RCP is $0.10450/kWh, less than half of what exported energy is charged.

Q126. HOW HAS THE ARIZONA SOLAR MARKET RESPONDED SINCE THE INTRODUCTION OF THE RCP MECHANISM?

A126. It has experienced a notable slowdown in the growth since the pre-RCP period. I examined application and installation data from the Arizona Goes Solar website for APS and TEP.[71] TEP also has an RCP mechanism, with the current value of $0.0868 / kWh lower than APS's tariff.[72] Figures 15 and 16 shows the three-month trailing average application and installation data for APS and TEP, respectively. In both utilities' territories, there was a notable spike in applications (circled in the charts below) prior to the commencement of the RCP tariff, followed by lower levels of applications in the years that follow. The spikes in the second and third year of the RCP were notably smaller than the initial wave, while installations have returned to levels last seen in roughly 2016 in APS and roughly 2014 in TEP.

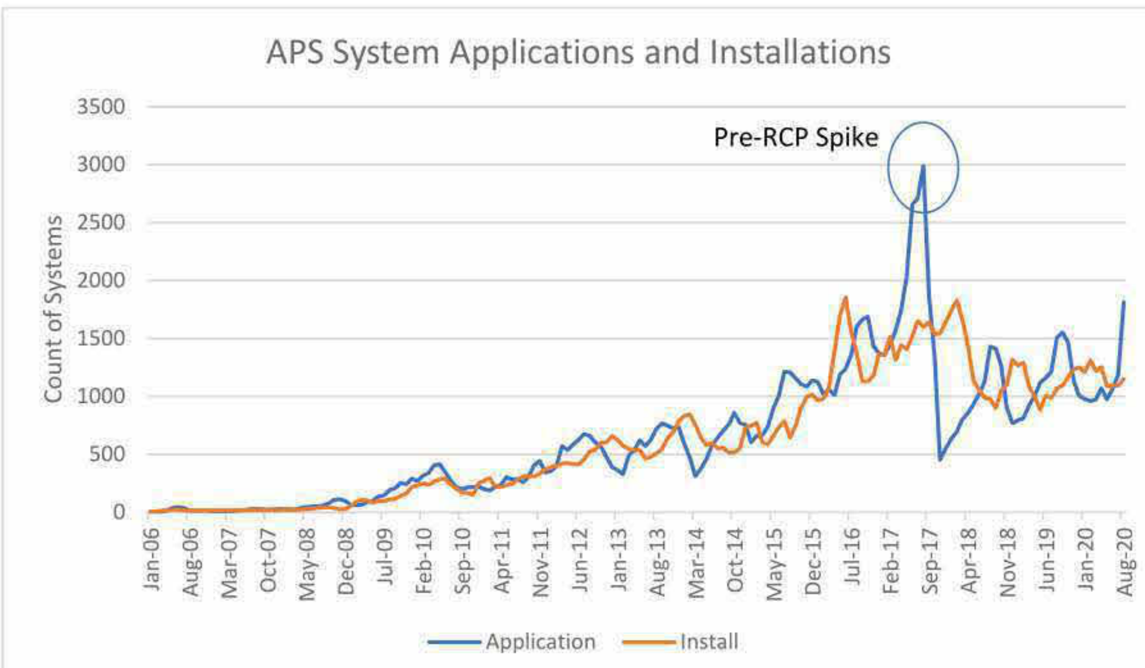


Figure 15 - APS Residential PV Applications and Installations

[71] http://azsolar.wpengine.com/utility-programs/. Accessed September 24, 2020. Data for USNE, which also implemented an RCP rider, is not available.
[72] https://www.tep.com/wp-content/uploads/2018/10/801-TEP-Statement-of-Charges.pdf

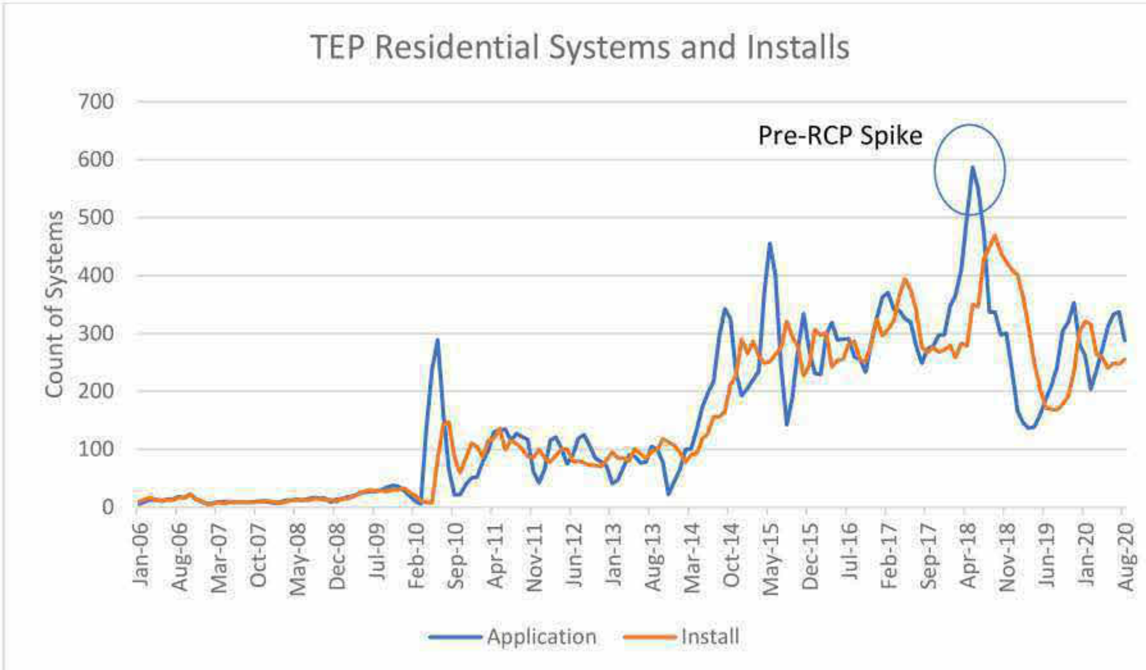


Figure 16 - TEP Residential PV Application and Installations

Although the solar market has not evaporated in APS's territory, the downswing in applications and installations in TEP's territory could be considered a leading indicator given its lower RCP rate – and should serve as a warning to the Commission if it does not freeze the RCP rate in APS' territory. TEP's March 2019 application level was the lowest it had been seen since early 2014, and it is unclear if it will rebound. Both utilities were experiencing consistent growth in installations dating as far back as 2008, but this growth appears to have been strongly impacted by the RCP rider.

Among other things, this slowdown in growth impacts the deployment of zero-carbon, renewable energy as well as the economic development and jobs that come along with it. Jobs data from the Solar Foundation[73] in Figure 17 below shows how two states (Arizona and Nevada) have seen substantial job losses associated with solar-unfriendly

[73] http://www.solarstates.org/#states/solar-jobs/2019

policies, while two other states without dramatic changes in policy have seen steady job growth over the past five years.[74]

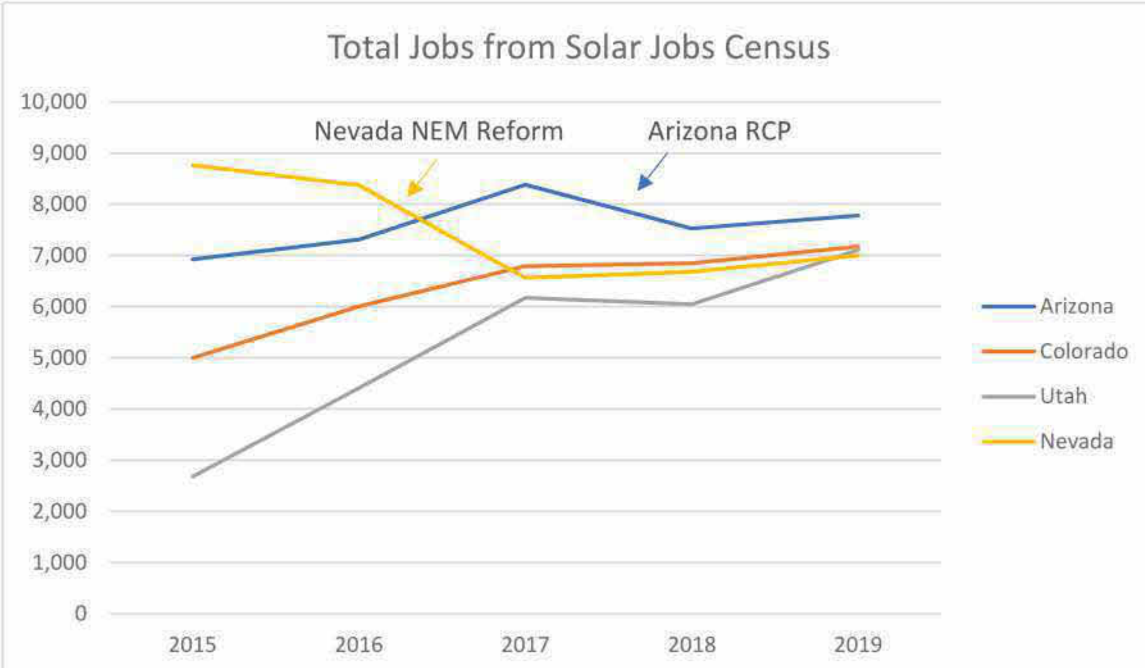


Figure 17 - Total Jobs from Solar Jobs Census

Q127. WHAT OTHER SOURCES OF UNCERTAINTY EXIST IN THE NEAR-TERM FOR THE ROOFTOP SOLAR INDUSTRY?

A127. One major source of uncertainty is the current ITC stepdown schedule. The federal ITC is one of the primary federal incentives available for solar and currently provides a credit equal to 26% of the system cost (having already stepped down from 30% on January 1, 2020). The ITC will fall to 22% for systems that are installed after December 31, 2020, and to 0% for customer-owned systems installed after December 31, 2021. The ITC step down schedule alone will have a deleterious impact on solar project economics in Arizona, eliminating a substantial source of customer savings. The impact of this, coupled with the RCP step down – if the Commission does not freeze it – could threaten the viability of Arizona's rooftop solar industry altogether.

[74] Nevada replaced traditional net metering with a mandatory three-part rate that did not create legacy rights for existing PV systems. Many solar companies immediately left the state. Although this change was subsequently reversed, the jobs have not fully returned.

Q128. HOW CAN THE COMMISSION HELP STABILIZE ROOFTOP SOLAR ADOPTION AND RETURN TO GROWTH LEVELS SEEN PRE-RCP?

A128. The Commission has already taken the first step, one that merits praise. In recognition of the challenging times facing the state amid the COVID-19 pandemic, the Commission voted to extend the stepdown by one year, leaving in place the current RCP credit of $0.10450 / kWh in place.[75] This is a necessary first step, but one that should be bolstered in the future by permanently freezing the RCP at its current level. This will help provide stability to the rate and allow customers to continue to adopt rooftop solar and allow Arizona to continue to support rooftop solar jobs that are put at risk every time the RCP declines.

Second, it can extend the initial lock-in duration for a given RCP rate. Currently, the rate lock-in expires after ten years, at which time the customer is converted to the then-current (and presently-unknown) future rate. Given rooftop PV systems have lifespans in 25-year range, there is considerably risk related to the uncertainty of not knowing the future export value.

Q129. WHY IS A TEN-YEAR LOCK IN PERIOD PROBLEMATIC FOR ROOFTOP SOLAR?

A129. It is problematic as it impacts the ability of a prospective customer to determine the economics of their system. Under the current process, the credit rate will be known for less than half of the life of the project. Since potential customers cannot know what the RCP rate will be in ten years, they are more likely to discount the future value of the credit. This in turn extends the economic payback period of the system, potential turning it from an investment worth making into one that is too risky.

Q130. HOW DOES THE LENGTH OF THE RCP LOCK DOWN COMPARE TO THE DURATION OF CERTAINTY THAT THE COMPANY GETS FOR ITS PROJECTS?

A130. It is much shorter. When the Company makes large investments in its system, it typically assumes lifetimes in the 30-50 year range (depending on the asset) and recovers its costs over

[75] COMMISSIONER LEA MARQUEZ PETERSON'S PROPOSED AMENDMENT NO. 1, Docket E-01345A-20-0113, approved September 22, 2020.

this time frame. However, if the utility were forced to fully recover the cost of assets in a time period much shorter than its useful life, or not given assurances that it will be able to recover costs decades in the future, it would substantially change the risk profile of the Company. In exchange for this additional risk, the Company would likely request a higher return on equity to compensate its shareholders, which would increase rates on its captive customers. Unfortunately, residential customers considering installing PV do not have a captive customers onto which they can pass risk; instead, a prospective customer facing more risk than they are comfortable with would simply not make an investment in rooftop solar.

Q131. HOW DOES THE TEN-YEAR LOCKDOWN COMPARE TO QUALIFYING FACILITIES IN THE PURPA PROCESS?

A131. It is also much shorter. The Commission recently ordered utilities to offer PURPA qualifying facilities standard contracts 18 years in length.[76] This is a reasonable length of time that more closely matches the system life of a PV system. There is no reason to provide developers of QF solar projects more revenue certainty than is provided to residential customers developing their own rooftop solar projects.

[76] *See* Decision 77512

V. APS IMPLEMENTS POLICIES THAT DISCRIMINATE AGAINST SOLAR CUSTOMERS

Q132. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A132. In this section, I discuss several policies that the Company implements that target solar customers. I focus on policies that impact currently-available rates including the R-Basic, R-XS, RE-TOU-E, R-2, and R-3. The first is limitations on eligibility for new customers who wish to install solar. The second is a Grid Access Charge ("GAC") applied to solar customers on the RE-TOU-E rate. The third is the load factor demand limiter that is enacted for non-solar customers but not for solar customers. The final is overly conservative assumptions related the maximum size system that a solar customer can install.

Q133. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A133. The Commission should prevent the Company from enacting policies that single out solar customers and treat them differently. The Company should allow any customer the option to remain on their current rate and install solar. For various reasons, shifting to a volumetric TOU-based rate or a demand-based may not be the economic choice for certain customers. Precluding customers on the various R-Basic tariffs from installing solar to further control their energy usage is unnecessary and discriminatory.

The GAC, by the Company's own admission, is not cost-based. It is only applied to customers on the RE-TOU-E tariff and provides a disincentive for choosing that tariff over the other solar-eligible R-2 and R-3 tariffs. Given the lack of a comprehensive value of solar analysis, the Company cannot say that the benefits of solar do not meet or exceed the costs. Absent this, the GAC should be rescinded.

The Company implements a "load factor-based demand limiter" that is designed to protect non-solar customers against unusually high demand spikes. While the concept of a demand limiter is useful to hedge against unexpected demand charges, the Company's decision to restrict this policy to non-solar customers is discriminatory. Rather than rescind any protection for excessive demand charges, the Company should modify its demand limiter to apply to solar customers.

The Commission should direct the Company to modify its EPR-6 (net metering) and RCP tariff that unnecessarily limit the size of solar systems, particularly for non-residential customers. In doing so, the Company would allow non-residential customers to size systems that are able to cover a more reasonable portion of their energy usage.

Q134. WHY DO YOU RESTRICT YOUR TESTIMONY IN THIS SECTION TO CURRENTLY AVAILABLE TARIFFS?

A134. The Company froze several legacy tariffs as part of a comprehensive settlement in Docket E-01345A-16-0036 ("Settlement") that involved multiple intervenors and was approved by the Commission. Revenue recovery issues related to customers who remain on the legacy rate designs were also included in the Settlement. These customers were allowed to remain on the legacy tariffs for a defined period of time. I do not propose to re-open these tariffs to new customers, nor address the duration that existing customers may remain on the tariffs. Rather, I focus here on matters that impact customers looking to install solar on a go-forward basis.

Customers Should be Able to Install Solar on Any Tariff

Q135. OF THE ACTIVE TARIFFS, WHICH ALLOW DISTRIBUTED GENERATION?

A135. The active R-TOU-E, R-2, and R-3 tariffs allow customers to install distributed generation. The R-XS and R-Basic do not. Further, if a non-solar customer currently taking service on the frozen R-Basic Large tariff wishes to install rooftop solar, they must switch tariffs.

Q136. ARE THERE OTHER RESTRICTIONS ON THE R-XS AND R-BASIC TARIFFS?

A136. Yes. The R-XS and R-Basic is available for customers with an average monthly usage between 0 and 600 kWh and between 600 kWh and 1,000 kWh, respectively. At the end of the test year, the Company had about 265,000 customers on the R-XS and about 116,000 customers on the R-Basic, which combined represent about 34% of the residential class.[77]

Q137. WHAT IS THE BASIS FOR THE COMPANY'S DECISION TO PREVENT CUSTOMERS FROM INSTALLING SOLAR ON THESE TARIFFS?

A137. The Company indicates that the Settlement "required non-grandfathered solar customers to be served under a time-of-use or demand rate."[78] While this may be the case, it does not mean that this is the most prudent policy when considered in isolation. New solar customers cannot choose net metering and must take service under the RCP tariff, which, with its separate value for exported energy, addresses some of the issues the Company had with the legacy tariffs.

Q138. AS A MATTER OF FAIRNESS, SHOULD CUSTOMERS BE ABLE TO CHOOSE THE TARIFF THAT THEY TAKE SERVICE ON?

A138. Yes. Customers should have the option to choose the tariff that works best for their individual lifestyle. Different customers have different abilities to shift usage from one period of the day to another. APS's offering of multiple rate options provides needed flexibility to accommodate these distinctions. However, requiring customers who wish to install solar to leave the underlying tariff that works best for them is a step in the opposite direction. Smaller usage customers should not have to choose between installing solar and remaining on a tariff that suits their needs.

The Grid Access Charge is Not Cost Based and Should be Reconsidered Until a Value of Solar Analysis has been Completed

Q139. WHAT IS THE GRID ACCESS CHARGE?

A139. The Grid Access Charge ("GAC") is a charge that is levied on solar customers on the R-TOU-E tariff. It is currently \$0.93 / kW_{DC} per month, and the Company has proposed to

[77] JEH-WP1DR Proof of Revenue.
[78] Attachment KL-28, SEIA 16.3.

increase it to \$0.951 / kW_{DC} per month.[79] For a typical 8 kW_{DC} system, this charge will add the equivalent of \$91.30 per year to a solar installation. Over a typical 25-year lifespan, this charge increases the cost of solar by about \$200 / kW_{DC}.[80] Given that 2020 estimated residential system costs in Arizona is \$2,690 / kW_{DC}, this represents a sizable cost premium to take service on this tariff.[81]

Q140. WHAT IS THE THEORY BEHIND THE GAC?

A140. The GAC is a fixed charge based on solar capacity. The theory is that the GAC helps recover more revenue from solar customers on a volumetric TOU rate. By shifting revenue recovery away from rates and to a charge based on installed capacity, the energy generated from a solar system will not impact the revenue collected by the GAC.

Q141. HOW WAS THE RATE OF THE GAC DETERMINED?

A141. It was originally instituted without the benefit of an evidentiary hearing and later was raised to its current level in the Settlement that resolved the last rate case. The GAC has never been subject to an evidentiary hearing and the Company has admitted that the GAC is not based on any cost-of-service analysis,[82] but contradictorily claims that it is provided "below cost-of-service."[83]

Q142. IF THE COMPANY DID NOT CREATE THE GAC BASED ON ANY COST OF SERVICE ANALYSIS, HOW CAN IT CLAIM IT IS BELOW THE COST OF SERVICE?

A142. APS appears to be relying on an old analysis from a previous case. In that old analysis, the Company "provided information showing that the revenues from solar customers on energy rates only recovered 38% of their cost of service, compared to 92% for residential customers as a whole."[84] This analysis was never subject to review in an evidentiary hearing.

---

[79] JEH-WP1DR Proof of Revenue.
[80] Assumes GAC increases of 2% per year and a 5% discount rate.
[81] Wood Mackenzie H1 2020 U.S. Solar PV System Pricing, June 2020.
[82] Attachment KL-29, SEIA 4.5a.
[83] Attachment KL-30, SEIA 9.11
[84] Attachment KL-31, SEIA 12.2.

Q143. IS THIS FIGURE REPRESENTATIVE OF ALL SOLAR CUSTOMERS OR JUST CERTAIN SOLAR CUSTOMERS?

A143. It is only representative of certain solar customers. Specifically, the Company is calling out solar customers on the Legacy Energy rates. One of these rates (Legacy E-12) was an inclining block rate with a top marginal rate of roughly $0.20 / kWh. Because solar reduced the most expensive energy first, solar customers were able to save considerably on their bills after installing solar. The Company updated its analysis in this case, showing that customers on the Legacy Energy rates pay 32% of their proposed cost of service through rates.[85]

However, it is my understanding that the revenue that is reported in the CCOSS for the Legacy rates is reduced by subtracting net metering credits at the full retail rate, rather than separately analyzing the consumption and export patterns.[86] As such, the low values for the Legacy rates do not provide an apples-to-apples comparison to the cost structure of the current rates.

Q144. IS THE LEGACY ENERGY AVAILABLE FOR NEW CUSTOMERS?

A144. No. The Legacy Energy (and Legacy Demand) rates were frozen as part of the Settlement to which the Company agreed and the Commission approved. It is disingenuous for the Company to stake its claim that the GAC is below cost of service when comparing it to a rate that is not open to new customers.

Q145. HOW DO SOLAR CUSTOMERS ON THE R-TOU-E RATE, WHICH IS ASSESSED A GAC, COMPARE IN THIS METRIC?

A145. Solar customers on the R-TOU-E metric fare much better on this metric. In my updated CCOSS analysis, these customers recover 83.9% of their cost of service through current rates even without considering the GAC charges.[87]

---

[85] This figure compares the current base rate revenue against the cost of service. The Company is not proposing to increase rates to collect this full amount, but instead to collect an average of 84.9% from the residential class. LRS_WP11DR Cost of Service Study Model.

[86] Direct Testimony of Briana Kobor on Behalf of Vote Solar at 32, Docket No. E-01345A-16-0036.

[87] The GAC revenues and costs are recovered through the LFCR Adjustor Rate, which is not part of base rates and is thus excluded from the CCOSS. Attachment KL-32, SEIA 5.6f.

Q146. HOW DO THESE FIGURES COMPARE TO OTHER CUSTOMER GROUPINGS?

A146. They compare well. As seen in Figure 18 below, the various residential subclasses sometimes collect more and sometimes collect less than the average residential customer.

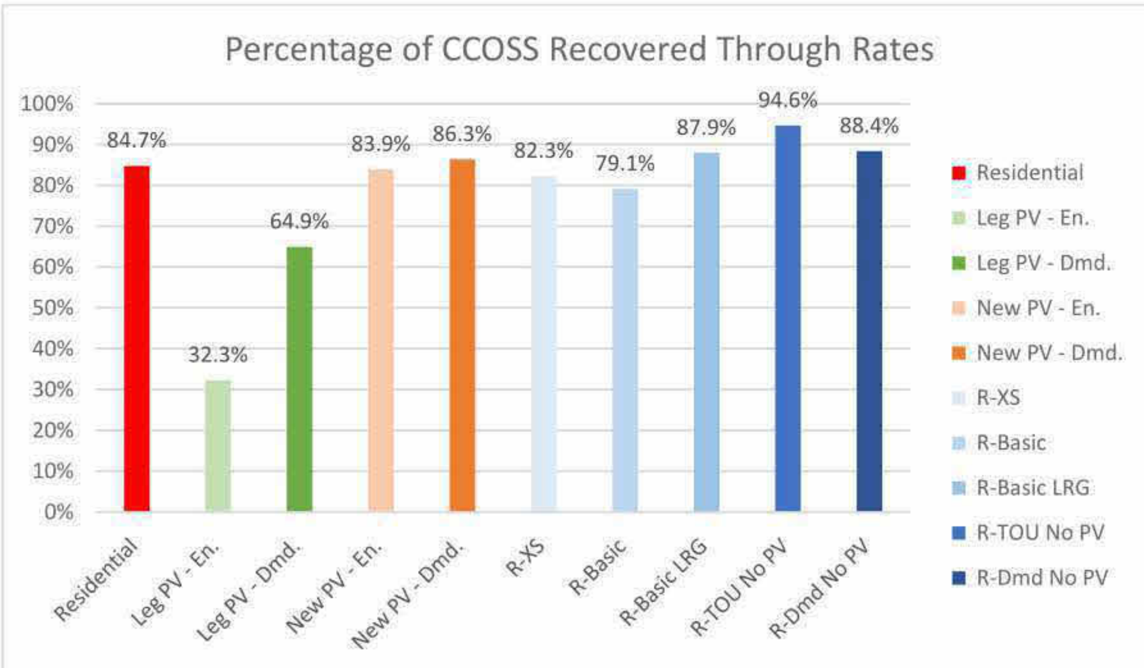


Figure 18 - Percentage of CCOSS Recovered Through Rates

The Legacy Energy and Legacy Demand tariffs are clear outliers, and that is part of the reason why these rates were closed to new customers. Customers on the R-TOU-E rate ("New PV – En." in the chart above) had revenue recovery in line with the average residential class, and have higher revenue recovery than the R-XS and R-Basic customer subgroups. The Company cannot use results from its closed legacy tariffs as a cost justification for the GAC on the R-TOU-E rate.

Q147. WHY DOES THE COMPANY NOT PROPOSE TO APPLY A GAC TO THE R-2 AND R-3 RATES?

A147. APS states that the GAC is not applied to the R-2 and R-3 rates "because they recover a portion of their capacity costs through demand charges."[88]

[88] Attachment KL-33, SEIA 5.6e.

Q148. WHAT DIFFERENCE DOES THIS MAKE?

A148. It does not make any difference. There is nothing about the recovery of revenue through demand charges that changes the fact that the GAC is not cost based. Demand charges do not automatically ensure that solar customers recover a higher percentage of their CCOSS through rates; the impact clearly depends on the specific design of the demand charges. If I were to speculate, I would opine that the Company in general would like to see more customers switch to demand charges as these rates tend to reduce revenue recovery volatility as compared to TOU energy rates. By not applying the GAC to demand rates, the Company forces solar customers to pay a premium to remain on a volumetric TOU rate that may better serve their needs.

Q149. WHAT DO YOU RECOMMEND WITH RESPECT TO THE GAC?

A149. The GAC is based on concept that solar customers on the R-TOU-E tariff are "not paying their fair share" through rates. However, the CCOSS shows that they are paying roughly the same as the average residential customer and more than non-solar customers on other rates. As such, the GAC should be eliminated.

The Company's Demand Limiter Should Be Extended to Solar Customers

Q150. WHAT ARE YOUR VIEWS ON DEMAND-BASED RATES FOR RESIDENTIAL CUSTOMERS?

A150. Generally, I am not in favor of demand-based rates for residential customers. Demand rates are often implemented based on a peak demand of any hour at any time during the month (individual non-coincident peak demand), which is not tied to cost-causation and creates perverse incentives.[89] To its credit, APS's demand-based rates are aligned with its on-peak periods. However, even though its demand charges are based on billing demand during the 3 PM to 8 PM on-peak period, the Company's use of year-round demand charges does not send meaningful price signals outside of the core summer months.

[89] Non-coincident demand charges do not send price signals to reduce usage during peak load hours. A customer who peaks during off-peak hours can have a perverse incentive to shift her load to peak hours. This would reduce her individual bill but impose more costs on the system as a whole.

Q151. HOW ARE CUSTOMERS ON THE R-2 AND R-3 RATES CHARGED FOR THEIR DEMAND?

A151. Customers are billed for demand charges monthly based on the single highest hour of average demand during the peak window of 3 PM to 8 PM on non-holiday weekdays. For instance, if a customer uses 4 kW in 107 of the roughly 108 on-peak hours a month, but uses 6 kW during the 108^{th} hour, they will be assessed a demand charge based on the 6 kW of usage. The demand charge is assessed during its 6-month "summer" (May – October) and "winter" (November – April) seasons, despite the Company's system load only peaking during the four core months between June and September.[90]

The demand rates for the R-2 tariff are lower than on the R-3 tariff, collecting 27% of total revenue on the R-2 tariff compared to 45% on the R-3 tariff.[91] For the R-2 tariff, the Company proposes to charge customers $8.688 / kW throughout the year. For the R-3 tariff, the Company proposes to charge customers $17.96 / kW in the "summer" and $12.59 / kW in the "winter". These demand charges consist of a flat rate of $4.09 / kW for distribution capacity with the remainder going towards generation capacity.[92]

Q152. IS A CUSTOMER ON THESE RATES ALWAYS CHARGED BASED ON THEIR ACTUAL PEAK DEMAND DURING THESE HOURS?

A152. No. The Company has implemented a "demand limiter" that reduces billing demand to the level that would occur if the customer experienced a "load factor" equivalent of 15% in a given month. Put more simply, the Company limits a customer's billing demand to avoid charging a customer that "occasionally sets an unusually high demand, relative to energy usage, in a particularly month."[93]

The load factor is a ratio of average demand to peak demand and is equal to the energy usage divided by peak demand times the relevant number of hours (8,760 for annual load factors and roughly 730 for monthly load factors). For instance, if a customer had a

[90] Attachment KL-34, RUCO 2.1, Attachment KL-35, SEIA 3.10.
[91] JEH-WP1DR Proof of Revenue.
[92] JEH-WP1DR Proof of Revenue.
[93] Attachment KL-36, SEIA 7.10c

constant load of 5 kW every hour of the year, their load factor would be 100%. If they had a peak load of 5 kW, but used an average of 2.5 kW per hour, their load factor would be 50%. The 15% load factor is equivalent to having a peak demand of 9.1 kW against 1,000 kWh per month of energy usage, or 13.7 kW against 1,500 kWh per month of energy usage.[94]

If a non-solar customer who uses 1,000 kWh in a month exceeds 9.1 kW in a month, their billing demand will be reduced to 9.1 kW. There is no limit on how much demand may be reduced or on how many times a customer can trigger the demand limiter.[95] Given that R-3 demand is charged at $17.96 per kW in the summer, this demand limiter can potentially save customers hundreds of dollars in a month.

Q153. DOES THE COMPANY EXTEND THE SAME COURTESY OF EXCUSING UNUSUALLY HIGH DEMAND TO SOLAR CUSTOMERS ON THESE TARIFFS?

A153. No, it does not. The 15% load factor demand limiter is not available to solar customers because, in APS's words "[i]t was not meant for solar customers who typically set a high demand relative to their energy usage in every month."[96]

Q154. HAS THE COMPANY PERFORM AN ANALYSIS TO SHOW THAT SOLAR CUSTOMERS "TYPICALLY SET A HIGH DEMAND RELATIVE TO THEIR ENERGY USAGE IN EVERY MONTH"?

A154. No, it has not. When asked to provide all such analysis, the Company pointed to the LRRs and stated:

> [T]he average monthly class load factor for the R-3 solar customers' delivered load, based on the on-peak demand, is 28%, which is significantly lower than the 42% result for non-solar customers on the R-3 rate. This result means that the solar customer purchases significantly less energy from APS relative to their demand compared with non-solar customers on the same rate.[97]

Q155. DOES THIS FIGURE ACTUALLY REPRESENT THE "AVERAGE MONTHLY CLASS LOAD FACTOR"?

A155. No, it does not. The value the Company refers to is actually the annual load factor based on the highest monthly coincident demand of the class, not the average monthly class load

---

[94] (1,000*12) / (9.13 * 8,760) = 0.15
[95] Attachment KL-37, SEIA 24.1b.
[96] Attachment KL-36, SEIA 7.10c.
[97] Attachment KL-38, SEIA 24.1d.

factor. The value for the solar customers is very low in part because of the sizable customer growth that I discussed previously. The peak demand value comes from the last month of the test year, when there were 2,400 customers, and is compared against the usage of the whole year, which started with only 429 customers. This skews the Company's value by comparing the peak demand of all customers against usage of roughly 60% of the customers.

The actual average monthly class load factor (found by averaging each month's CP load factor) for solar customers on the R-3 tariff is 58.5%. This same value for non-solar customers on the R-3 tariff is 68.9%. While the solar load factor is somewhat lower, it is hardly a significant difference.

Q156. WHEN THE COMPANY PROPOSED THE DEMAND LIMITER, WHAT WAS ITS EXPECTATION?

A156. In testimony supporting the implementation of the demand limiter, APS stated that it "believes that this type of inadvertent high demand would be very unlikely given our experience with residential demand rates and the one-hour calculation discussed above."[98] While "very unlikely" was not quantified, the Company appeared to have believed that the demand limiter would only be triggered rarely.

Q157. HAVE YOU ESTIMATED HOW OFTEN THE DEMAND LIMITER IS TRIGGERED FOR CUSTOMERS ON THESE TARIFFS?

A157. Yes, I have. I analyzed billing information on the R-2 and R-3 tariffs for both solar and non-solar customers.[99] Figures 19 and 20 below show the load factors for solar and non-solar customers on the R-2 and R-3 tariffs, respectively. Customers on the R-2 tariff used an average of 14,528 kWh per year, while customers on the R-3 tariff were larger and used 20,383.[100] Because the Company rounds peak demand to the nearest 0.1 kW, and because billing cycles do not always correspond to calendar months, the spikes around 15% load factor for non-solar customers represent the application of the demand limiter.

---

[98] Attachment KL-39, SEIA 3.14_APS19RC00390_Miessner Direct Testimony 16-0036
[99] Attachment KL-40, SEIA 2.3.
[100] Initial 1.31_ExcelAPS19RC00282_2018 2019 Load Research Report.

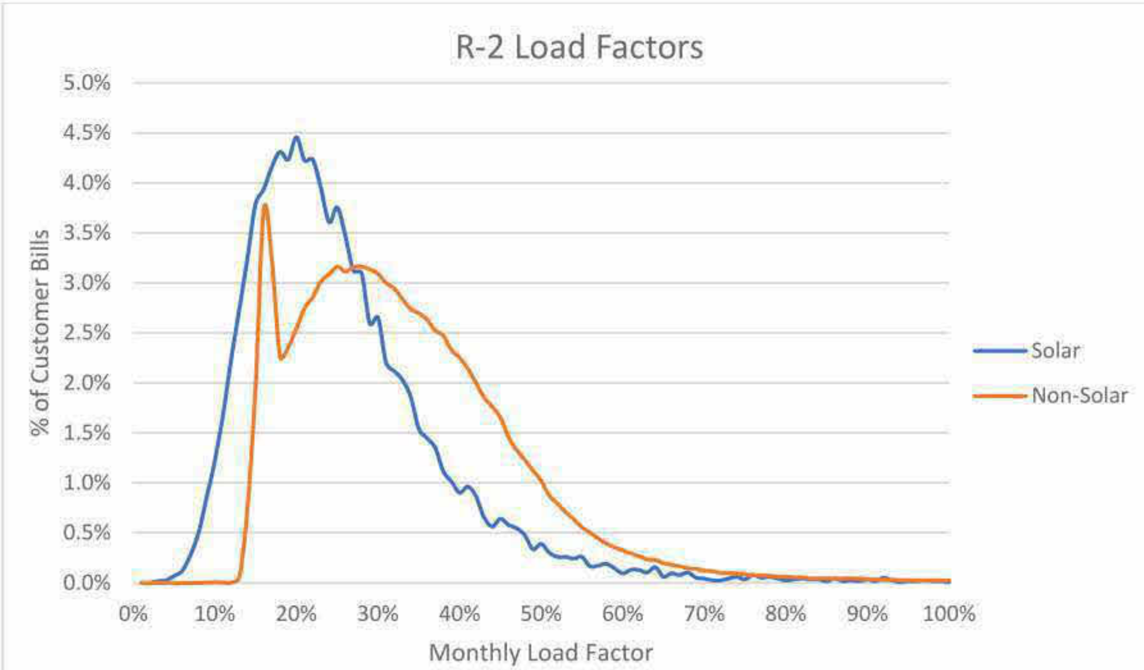


Figure 19 - R-2 Load Factors

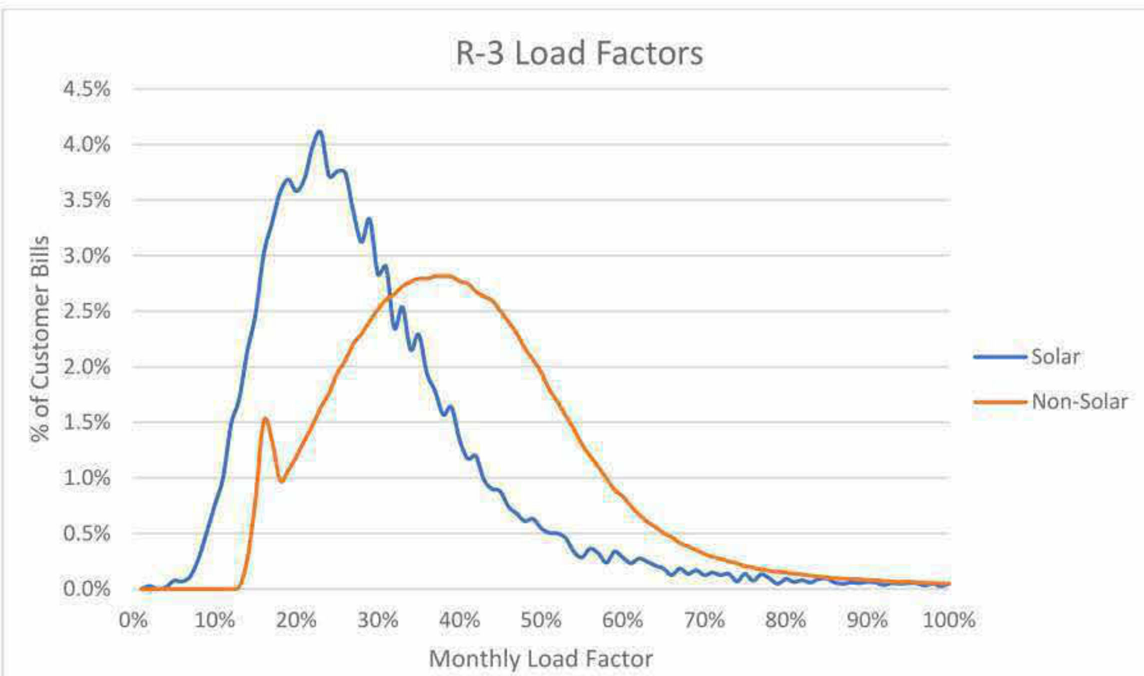


Figure 20 - R-3 Load Factors

Q158. HOW DO YOU INTERPRET THESE FIGURES?

A158. I would question whether the incidence of demand limiters in the Company data is "very unlikely" as it anticipated. The Company identified nearly 44,000 monthly bills for non-solar customers that triggered the demand limiter on each of the R-2 and R-3 tariffs.[101] This represents approximately 5.7% and 2.3% of all non-solar monthly bills on the R-2 and R-3 tariffs, respectively. The demand limiter is much more common on the R-2 tariff than on the R-3 tariff. This is likely due to the higher average energy use of customers that require higher demand levels trigger the 15% load factor limit.

Q159. DO THESE CHARTS DISCREDIT THE COMPANY'S CLAIM THAT SOLAR CUSTOMERS "TYPICALLY" SET A HIGH DEMAND RELATIVE TO THEIR ENERGY USAGE IN "EVERY" MONTH?

A159. Absolutely. While the average load factor for solar customers is lower than for non-solar customers, it is hardly the case that solar customers see very low load factors in every month. In fact, only 15.3% and 9.6% of solar bills on the R-2 and R-3 tariffs, respectively, have load factors under 15%.

Q160. HAS THE COMPANY ESTIMATED THE IMPACT OF THIS DEMAND LIMITER ON ITS REVENUES?

A160. Initially the Company responded that it had not, but in a subsequent discovery response, it did calculate the impact of this policy.[102,103] In its analysis, the demand limiter prevented $1.06 million in billing from non-solar customers due to unusually high billing demands. Some customers experienced "unusually high" billing demand in every month of the year, while more than 1,700 customers triggered the demand limiter in 6 or months in a year. The average saving from the demand limiter was $23.46 per year, although a few customers saved more than $1,000 per year.

Meanwhile, solar customers who were not offered this same protection were charged an additional $44,423 than if they had been subject to the demand limiter. The lower value is largely due to the smaller number of solar customers on these tariffs; the average increased charge of $25.07 per year was nearly identical to the average savings from non-solar customers.

---

[101] Attachment KL-41, Vote Solar 1.3.
[102] Attachment KL-42, SEIA 7.10b.
[103] Attachment KL-41, Vote Solar 1.3.

Q161. WHAT DO YOU RECOMMEND WITH REGARD TO THE DEMAND LIMITER?

A161. I recommend that the demand limiter be extended to solar customers on the R-2 and R-3 tariffs. Demand-based rates are always challenging for residential customers to manage given high usage during one single hour a month can cost customers potentially hundreds of dollars. The mere fact that a customer has a solar system does not mean that they will never experience unexpected instances of high demand. The Company's data clearly show that solar customers do not experience high demands in every month relative to their usage, just as it shows that some non-solar customers regularly experience "unusually" high demands. The only appropriate action is to extend the demand limiter to all customers – including those with solar systems – on the R-2 and R-3 tariff.

The Company Should Revise its Maximum System Size Methodology

Q162. WHAT LIMITS DOES THE COMPANY PLACE ON PV SYSTEM SIZES UNDER ITS RCP AND EPR-6 TARIFFS?

A162. The Company has the same size limitations on both the RCP rider and its EPR-6 tariff (the net metering tariff which is closed to new residential customers but open to new non-residential customers). The specific language from the EPR-6 tariff follows:

> 4. For qualifying residential facilities, the nameplate capacity cannot be larger than the following electric service limits:
>   a) For 200 Amp service, a maximum of 15 kW-dc.
>   b) For 400 Amp service, a maximum of 30 kW-dc.
>   c) For 600 Amp service, a maximum of 45 kW-dc.
>   d) For 800 Amp service and above, a maximum of 60 kW-dc; and
> 5. For all qualifying residential and non-residential facilities over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8 kW-ac, the maximum system size that could be installed would be 12 kW-dc).[104]

[104] Rate Rider EPR-6.

Q163. WHERE DO THESE RESTRICTIONS COME FROM?

A163. The Company indicates they were approved by the Commission in the Settlement as a "reasonable way to implement the size requirements" under Arizona's net metering rules (A.A.C. R-14-2-2302).[105] However, it does not appear that the Commission specifically opined on these provisions, but rather accepted the EPR-6 tariff language along with many other provisions of the Settlement.

Q164. WHAT IS THE SPECIFIC LANGUAGE IN THE ARIZONA RULES?

A164. The relevant portion of the Arizona Rules state

> 13. "Net Metering Facility" means a facility for the production of electricity that:
>
> a. Is operated by or on behalf of a Net Metering Customer and is located on the Net Metering Customer's premises;
>
> b. Is intended primarily to provide part or all of the Net Metering Customer's requirements for electricity;
>
> c. Uses Renewable Resources, a Fuel Cell, or CHP to generate electricity;
>
> d. Has a generating capacity less than or equal to 125% of the Net Metering Customer's total connected load, or in the absence of customer load data, capacity less than or equal to the Customer's electric service drop capacity; and
>
> e. Is interconnected with and can operate in parallel and in phase with an Electric Utility's existing distribution system.[106]

Q165. HOW IS "TOTAL CONNECTED LOAD" DEFINED IN THE RULES?

A165. The term "total connected load" is not defined anywhere in R14-2-2301 and does not appear anywhere else in all of Title 14. The Company has chosen to interpret this as the maximum one-hour peak demand measured in AC over the prior twelve months, however, this definition is not in the Rules. Despite this, it also had acknowledged in two places that potential total connected load is much higher than the average one-hour demand.

The first is in a previous docket discussing the demand limiter. The Company produced a chart showing an illustrative example of the difference between instantaneous loads and one-hour demand averages. Figure 21 below reproduces this figure.[107] While this figure was illustrative, it is consistent with fluctuations in demand (such as turning on a

---

[105] Attachment KL-43, SEIA 16.2.

[106] Rule R14-2-2301. Available at https://apps.azsos.gov/public_services/Title_14/14-02.pdf

[107] Direct Testimony of Charles A. Miessner On Behalf of Arizona Public Service Company, Docket No. E-01345A-16-0036 at 29.

toaster or running a pump for a few minutes) that are not sustained for an entire hour. In this example, the maximum load is twice the average load. Although the specific value will vary from customer to customer, it is undeniable that the maximum connected load will exceed the maximum one-hour demand. It is also undeniable that the Company's assets are able to handle these instantaneous demand peaks safely and reliably.

Figure 3 Illustrative Example of Instantaneous Versus One-Hour Demands

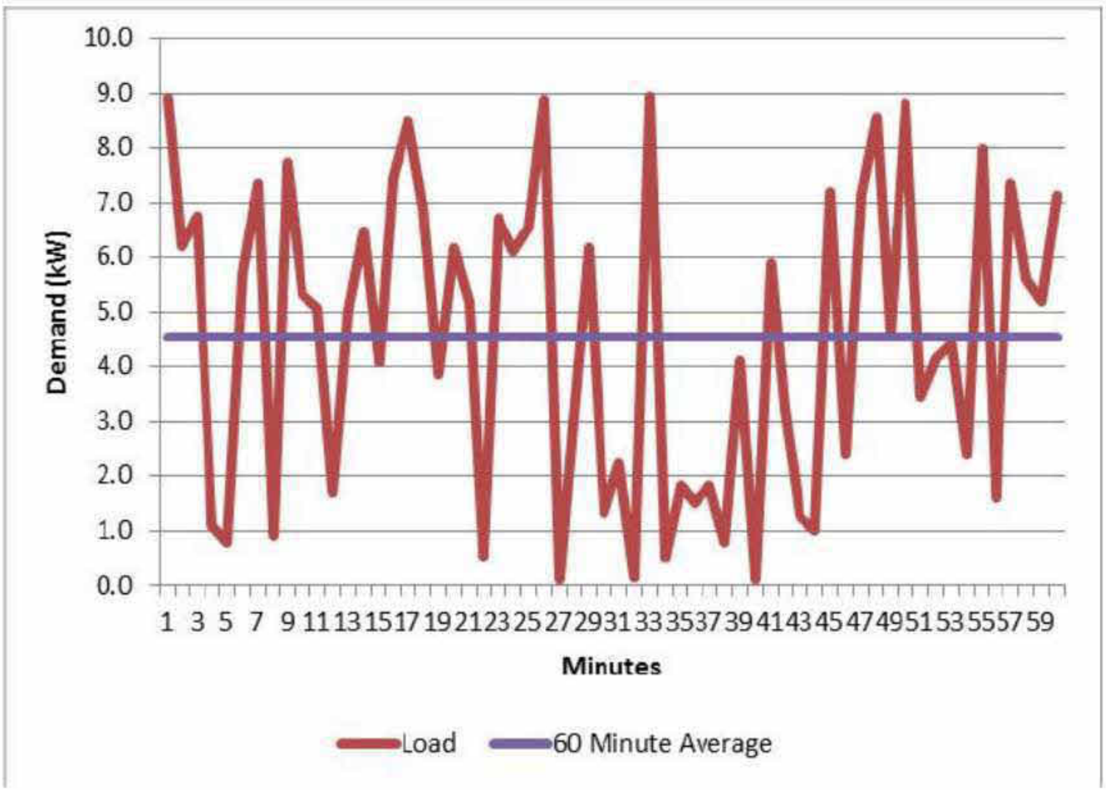


Figure 21 - APS Example of Instantaneous Load vs. One-Hour Demands

The second is in its discussion of maximum amount of load that can be served through a customer's service drop. It correctly calculates that a 200-amp service can support 38.4 kW_{AC}, even if the Company assumes a customer on a 200-amp service will have a maximum demand of 12.2 kW_{AC}.[108] Both of these examples suggest that the Company's

[108] Attachment KL-43, SEIA 16.2.

distribution equipment can safely and reliably handle much higher demand levels than what is obtained through a one-hour average reading.

Q166. SHOULD THE "GENERATING CAPACITY" OF A SOLAR SYSTEM MEASURED IN KW_{DC} BASED ON THE SOLAR PANELS OR KW_{AC} BASED ON THE INVERTER RATING?

A166. It should be measured in kW_{AC} based on the inverter rating as this is the only relevant metric when the system is connected to the Company's distribution grid. The inverter is the component that takes power from the PV panels in direct current ("DC") and transforms it to alternating current ("AC") for use in the house or on the grid. Solar systems interconnected to the Company's system must provide power in the same 60 hertz AC form as every other generator. The nameplate, or kW_{DC}, rating of the system is not determinative of the power a solar system can connect to the grid. While there are guidelines that developers typically follow on the ratio of kW_{DC} to kW_{AC} (called the inverter load rating, or "ILR"), customers can vary the number of panels that are connected to an inverter to maximize their production through the year.

Typical ILRs for are around 1.2 for residential customers and around 1.25 for commercial customers, but the exact configuration will depend on project-specific details. If a customer were to oversize the panels relative to the inverter (i.e. increase the ILR) to increase the total energy the system produces, the maximum system power will still be limited based on the kW_{AC} rating of the inverter. For example, if one connected 20 kW_{DC} to a 15 kW_{AC} inverter, the maximum power produced would be identical to connecting 18 kW_{DC} to a 15 kW_{AC} inverter; the rest of the power would be clipped and not sent to the grid.

Q167. GIVEN THIS, WHY DOES THE COMPANY LIMIT THE SYSTEM SIZE BASED ON THE KW_{DC} RATING OF THE PANELS?

A167. It is unclear. It may be because customers are more used to seeing system sizes quoted in kW_{DC}, but this is immaterial to setting size limits of systems that are connected to the Company's grid. Developers are obviously familiar with the distinction between AC and DC ratings and can appropriately size systems in DC for their customers while meeting AC rating requirements from the Company.

Q168. DID THE RECENTLY APPROVED INTERCONNECTION REGULATIONS ADDRESS THIS ISSUE?

A168. It did. New regulations were promulgated on March 20, 2020 that governed the interconnection process for distributed resources. In those regulations, the "Maximum Capacity was defined as "The nameplate AC capacity of a Generating Facility: or If the Operating Characteristics of the Generating Facility limit the power transferred across the Point of Interconnection to the Distribution System only"[109] The AC power rating was specifically called out, and should guide all limitations that the Company places on distributed resources.

Q169. DOES THE COMPANY BILL ALL NON-RESIDENTIAL CUSTOMERS BASED ON THEIR ONE-HOUR DEMAND?

A169. No. Only the smallest non-residential customers on the E-32 XSD are charged based on a one-hour maximum demand. All other non-residential customers are charged based on the highest 15-minute demand period in a month. As suggested by Figure 21 above, the highest 15-mintue demand average will be higher than the highest one-hour demand average.

Q170. DID YOU ANALYZE HOW OFTEN THE NON-RESIDENTIAL PV SYSTEM LIMITATIONS WOULD PREVENT CUSTOMERS FROM OFFSETTING THEIR ANNUAL LOAD THROUGH ON-SITE SOLAR GENERATION?

A170. Yes. Using billing data for non-residential customers, I calculated what size hypothetical PV system could be installed based on the customer's previous 12 months of demand.[110] While the billing demand values for the vast majority of these customers represented 15-minute demand, I did not have the data to calculate hourly demand. As such, it is likely that the PV maximum system size in my analysis is larger than would be allowed under the Company's

---

[109] Arizona Administrative Register, 26 A.A.R. 473, Notice of Final Rulemaking regarding the Interconnection of Distributed Generation Facilities Rules, A.A.C. R14-2-2601 through R-14-2-2628. Available at https://docket.images.azcc.gov/E000005485.pdf

[110] Attachment KL-44, SEIA 16.5. Roughly 113,000 customers had 12 months of data. The maximum annual kW_{AC} demand was grossed up by 150% to set the kW_{DC} of the hypothetical system.

interconnection rules as the 15-minute demand levels are likely higher than the one-hour demand levels.

I then calculated the generation from this system, and compared it to the annual energy usage of the customer.[111] This was repeated for each of the Company's core commercial tariffs that had billing demand values and sizable customer populations.[112] Unfortunately, the roughly 87,000 customers that had 12 months of data (more than 75% of the data set) were served on the E-32 XS tariff and did not have billing demand values. There were about 280 customers on the E-32 XSD tariff that provides some insight into the result for smaller commercial customers, although the fact these customers self-selected into a demand-based tariff means they may not be representative of the rest of the E-32 XS class.

Figure 22 below shows the amount of annual energy that could be produced from the maximum system size allowed under the Company's interconnection guidelines. In each tariff, there are customers with lower load factors that would be able to cover their entire annual usage under the Company's current limits. These customers are located on the left side of the chart. But as a customer's load factor increases, their demand falls relative to their energy usage. This means that the allowable PV system size also falls relative to their annual energy. For the E-32 L tariff, only about 12% of customers could size PV systems large enough to cover their entire annual usage. The situation is not much better for E-32 XSD customers (21%) or E-32 M (26%). The "best" result below is for the E-32 S class, where roughly half of customers could install a system to cover their annual usage.

[111] NREL's PV-Watts calculator shows 1,690 kWh / kW_{DC} for a south-facing system with premium panels at a 10-degree tilt. Actual installations may not attain these levels of output. https://pvwatts.nrel.gov/pvwatts.php
[112] The various E-32 TOU tariffs represented a small fraction of each customer group.

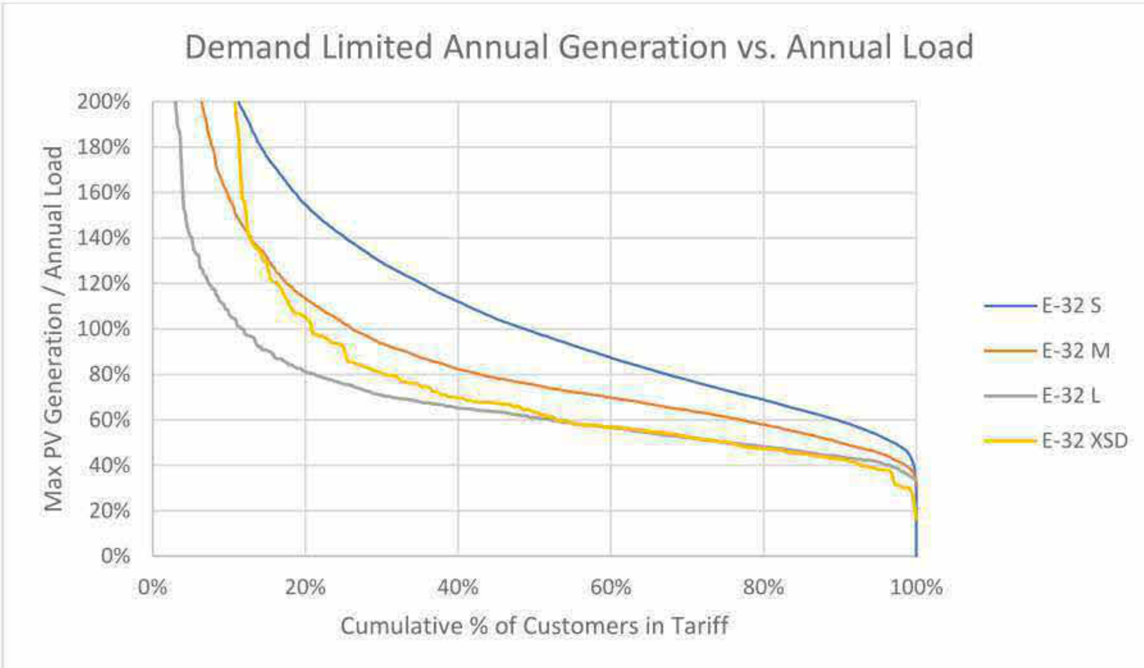


Figure 22 - Demand Limited Annual Generation vs. Annual Load

Q171. WHY IS THIS AN ISSUE?

A171. Existing commercial customers with high load factors are disproportionally harmed under this provision. As a first matter, based on the Rules, a new customer with no demand history can install a system sized up to its service drop limit. As suggested by the residential limits above, this value is likely to be multiple times higher than a limit based on demand history. Clearly, this has been deemed a safe practice based on its inclusion in the Company's tariff language.

The Company's methodology converts an overly-conservative interpretation of total connected load into smaller system sizes. In some cases, this can negatively impact project economics to the point where a decision to move forward cannot be met. Corporate commitments to renewable energy and carbon reduction are necessarily based on energy usage, not peak demand. Customers that are required to limit the size of their system may not be able to attain goals related to renewable energy or carbon reduction.

Further, this restriction interacts poorly with the declining block structure of the customer. Customers on the E-32 M and E-32 L tariff may be limited to offsetting the lower-cost marginal rates and will have more difficulty offsetting the more expensive demand and energy charges in the initial block.

Q172. WHAT DO YOU RECOMMEND THE COMPANY DO REGARDING ITS INTERCONNECTION LIMITS FOR NON-RESIDENTIAL CUSTOMERS?

A172. I recommend the Commission require the Company to follow the same protocol as Tucson Electric Power Company ("TEP"). TEP's net metering documentation states "No system may exceed 125% of connected load for that meter, where connected load is defined as the maximum demand divided by 0.6."[113] For a 1 kW_{AC} maximum 15-minute billing demand, this will produce a total connected load of 1.67 kW_{AC}. Multiplying this by 125% will produce a maximum PV system of 2.08 kW_{AC} for each kW_{AC} of billing demand. Clearly, TEP is able to safely and reliability interconnect customer's PV systems even with these higher assumptions. There is no reason that customers served by APS should be restricted further.

Q173. HOW WERE THE RESIDENTIAL SYSTEM SIZE LIMITS DETERMINED?

A173. The residential system size limits (which apply to both the legacy EPR-6 and the current RCP riders) are 125% of the Company's design maximum load for customers. APS indicates that residential customers on a 200-amp service are designed to serve a maximum load of "roughly 12.23 kW". The system size limit for a 200-amp service is 15 kWDC, which is very close to 12.23 * 1.25% = 15.3. System limits for 400-amp service (24.46 kW demand *125% = 30.6 kW compared to a 30 kW_{DC} limit), 600-amp service, and 800-amp service follow the same pattern.[114]

---

[113] In the Matter of the Application of Tucson Electric Power Company for Approval of its 2020 Renewable Energy Standard Implementation Plan, Exhibit 8. Docket E-01933A-19-0149. Available at https://docket.images.azcc.gov/0000198844.pdf

[114] Attachment KL-45, SEIA 26.1.

Q174. WHAT DO YOU RECOMMEND THE COMPANY DO REGARDING ITS INTERCONNECTION LIMITS FOR RESIDENTIAL CUSTOMERS?

A174. The Company's basis for setting these limits for residential customers is incorrect. If it is going to use the maximum assumed demand of a customer to set the limit, then the Rules require that a customer be able to interconnect 125% of this value. This interconnection limit must be in kW_{AC}, as this is the only type of power that connects to the Company's grid and is consistent with the new interconnection regulations. The Commission should require the Company to update the system size limits for residential customers in its EPR-6 and RCP riders to 15 kW_{AC}, 30 kW_{AC}, 45 kW_{AC}, and 60 kW_{AC} for 200-amp, 400-amp, 600-amp, and 800-amp service, respectively.

Q175. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FROM THIS SECTION OF YOUR TESTIMONY.

A175. I recommend the Commission require the following changes:

- Allow customers to install solar on any active residential tariff.
- Eliminate the GAC.
- Extend the demand limiter to solar customers on the R-2 and R-3 rates.
- Adopt TEP definition of connected load as the maximum demand divided by 0.6, and after multiplying this value by 125%, apply it to the AC inverter rating
- Change the system size limits for residential customers based on the inverter rating to 15 kW_{AC}, 30 kW_{AC}, 45 kW_{AC}, and 60 kW_{AC} for 200-amp, 400-amp, 600-amp, and 800-amp service, respectively.

VI. THE COMPANY'S NON-RESIDENTIAL TARIFFS CAN BE IMPROVED

Q176. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A176. In this section, I discuss issues related to the Company's non-residential tariffs. I analyze the primary E-32 set of tariffs and examine how the Company transitions customers between the various sizes. I discuss how elements of the rate designs themselves, including the demand ratchet on the E-32 L tariff and the declining block structure of the E-32 S and E-32 M tariffs, hinders adoption of demand side management practices, including installing solar, by non-residential customers.

Q177. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A177. I recommend the Company reanalyze aspects of its non-residential tariffs to increase equity between customers and support the installation of non-residential solar on a broader base of customers. There is a distinct disincentive for high load factor customers to downsize from a "larger" tariff to a "smaller" one, such as moving from E-32 L to E-32 M. This is clearly contrary to the Company's goals to reduce peak demand and creates perverse incentives for non-residential customers. There is also a steep penalty for low load factor customers that are bumped up from smaller tariffs to larger ones that is out of alignment with the actual loads the customers are placing on the system.

Demand ratchets have always been problematic for non-residential customers and produce a barrier to making demand-side management investments including distribution solar and energy storage solutions. The Company's 80% demand ratchet for customers on the E-32 L tariff is unnecessary and should be reduced or removed.

The declining block structure of the E-32 M and E-32 L tariffs also does not encourage demand reduction, particularly on the E-32 L tariff. This outdated rate design should be replaced with one that encourages appropriate usage of the grid and does not disproportionally favor large customers over small customers within the tariff.

Finally, the Company's energy storage pilot program rate E-32 L SP suffers from several design flaws that will prevent it from meeting its goal. Billing customers on non-coincident peak is not aligned with standard industry load management practices and focuses demand reduction on times that might not be aligned with the grid as a whole.

The E-32 Tariffs Disincentivize Demand Reduction for Certain Customers

Q178. PLEASE DESCRIBE THE COMPANY'S PRIMARY NON-RESIDENTIAL TARIFFS.

A178. The Company primary non-residential tariffs are designated E-32 and range from XS to Large. The E-34 tariff is available for customers larger than the E-32 L. These tariffs come in a standard and a time-differentiated version, and the tariff for the smallest class comes in both a two-part volumetric rate and a three-part demand rate. Table 11 below contains the key rate design information. My analysis focuses on the non-TOU versions of these tariffs as, except for extra-large customers on the E-34 tariff, they serve the vast majority of customers.

	E-32 XS	E-32 XSD	E-32 S	E-32 M	E-32 L	E-34
Eligible Demand (kW)	0 - 20	0 – 20	21 - 100	101 - 400	400 - 3,000	3,000+
Demand (Secondary)						
First 100 kW		$7.703	$11.530	$12.280	$25.704	$22.082
Add'l kW		$7.703	$6.702	$7.004	$17.812	$22.082
Energy						
Summer						
First 5,000 kWh	$0.13867					
Add'l kWh	$0.07700					
First 200 kWh / kW		$0.10198	$0.10950	$0.10708	$0.05649	$0.04043
Add'l kWh		$0.10198	$0.06861	$0.06605	$0.05649	$0.04043
Winter						
First 5,000 kWh	$0.12193					
Add'l kWh	$0.05990					
First 200 kWh / kW		$0.08258	$0.09330	$0.09075	$0.03802	$0.04043
Add'l kWh		$0.08258	$0.05243	$0.04972	$0.03802	$0.04043
Customers	**100,521**	**395**	**19,307**	**4,221**	**826**	**20**
TOU Variation Customers		**282**	**155**	**73**	**61**	**30**

Table 11 - Non-Residential Rate Comparison

Three of these tariffs (E-32 S, E-32 M, and E-32 L) use a declining block structure for demand charges, with the first 100 kW at a higher rate and subsequent kW at a lower rate.

Three tariffs (E-32 XS, E-32 S, and E-32 M) use the same type of declining block structure for energy rates, with the E-32 XS based on total summer consumption and the others based on the first 200 kWh per kW consumed.

Q179. DO CUSTOMERS CHOOSE WHAT TARIFF THEY WISH TO BE ON, OR DOES THE COMPANY ASSIGN THEM TO A TARIFF?

A179. Customers may choose between the standard and TOU variations, or between the E-32 XS and E-32 XSD, but the Company assigns customers to the specific rate based on their average summer demand levels. Each tariff contains similar language to the following: "The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average summer monthly maximum demand, as determined by the Company each year. This determination will be made annually."[115] The Company further clarified that it switches customers on the January billing period based on the 15-minute metered demand levels.[116]

Q180. HOW WELL ALIGNED ARE THE "EDGES" OF THE TARIFFS?

A180. Some are more aligned than others for demand levels that are close to the breakpoints between tariffs. Because the Company assigns customers to tariffs on an annual basis, it is possible for customer that hovers near the demand level thresholds between tariffs to be moved back and forth over sequential years. For instance, a customer that has a peak demand around 100 kW may find themselves placed in either the E-32 S or the E-32 M based on a single 15-minute interval in summer months. The Company should seek to reduce the rate shock that could potentially befall these edge customers.

I examined the edge cases for customers that fall on the line between tariffs.[117] Figures 23 and 24 below show the results that occur for a customer switching from the smaller rate to the larger rate (e.g. from E-32 S to E-32 M) based on the demand threshold. I

[115] Rate Schedule E-32 XS.
[116] Attachment KL-46, SEIA 26.2.
[117] Attachment KL-44, SEIA 16.5.

also included an example of an XS customer choosing between the E-32 XS and E-32 XSD variants.

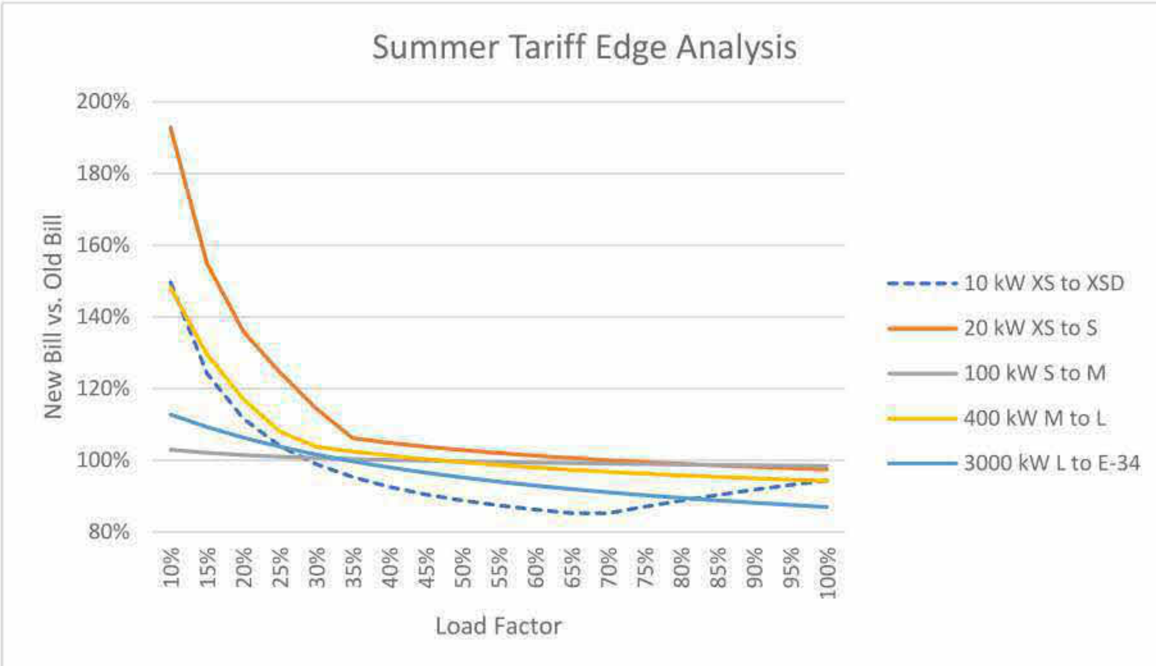


Figure 23 - Summer Tariff Edge Analysis

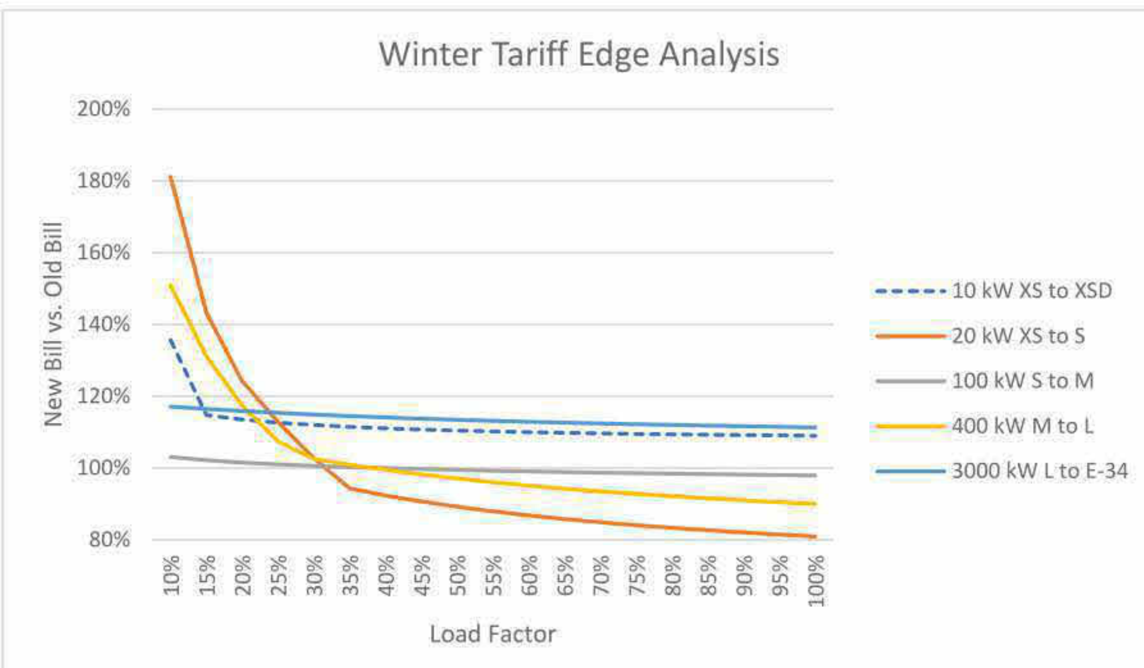


Figure 24 - Winter Tariff Edge Analysis

For low load factor customers, there is a steep premium associated with a switch from the E-32 XS to E-32 S and from the E-32 M to E-32 L. The increase in bills when moving from the E-32 S to E-32 M and E-32 L to E-34 is lower, but still can result in an unpleasant increase in bills.

Most of the tariffs switch from imposing a cost to providing a benefit when moving up to the next largest tariff, although the load factor where the switch occurs varies by tariff and by season. E-32 XS, E-32 S, and E-32 M customers that have a winter load factor over roughly 30-35% will see lower winter bills, but they will need higher load factors to see similar reductions in summer bills. As the Company uses "summer" rates for half the year, it is not immediately obvious whether an individual customer with a medium load factor will see an increase or decrease in their annual bill.

Q181. IS THERE ANY MATERIAL IMPACT TO THE SYSTEM OR TO SYSTEM COSTS OF AN INDIVIDUAL CUSTOMER INCREASING ITS AVERAGE SUMMER DEMAND FROM 19 KW TO 21 KW OR FROM 399 KW TO 401 KW?

A181. No. The tariff placement determination is based on the average summer metered demand, which means that customers will have months that are higher and lower than their average. Unless these small changes occur during the exact 15-minute or one-hour period when the local distribution system or overall system is peaking, there is no impact on system reliability or costs of a customer having small increase of decrease in their demand. And even if a customer was unlucky enough to experience their peak at the exact time of the system peak, the contribution of a few hundred customers is unlikely to produce anything other than a *de minimus* impact.

Q182. WHAT IS THE OVERALL DISTRIBUTION OF CUSTOMER LOAD FACTORS ON THE NON-RESIDENTIAL TARIFFS?

A182. Monthly load factors vary by tariff and by season. Generally, as seen in Figure 25 below, smaller customers have lower load factors, and customers have higher load factors in summer months than winter months. There are of course individual exceptions to the rule, but the trends are fairly consistent as one moves from E-32 S to E-32 M to E-32 L. The median summer load factor is about 41%, 52%, and 60% for E-32 S, E-32 M, and E-32 L, respectively.

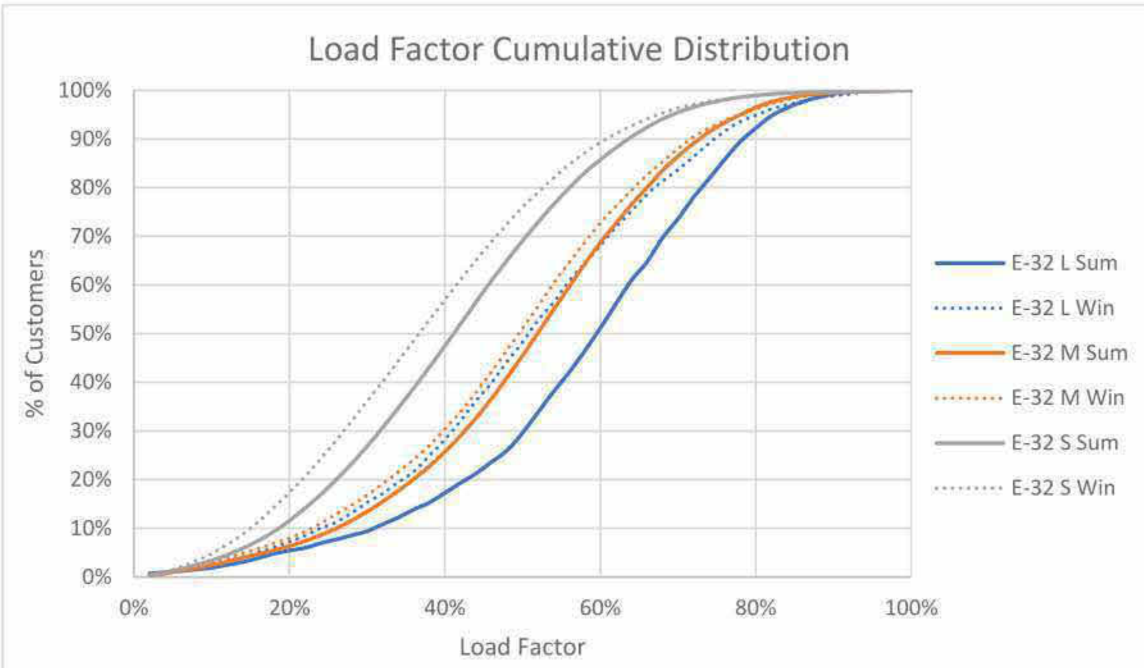


Figure 25 - Load Factor Cumulative Distribution

Q183. HOW MANY CUSTOMERS ARE SWITCHED FROM ONE TARIFF TO ANOTHER?

A183. The tariff changes occur with some frequency. In the data that the Company provided for the test year, I calculated that roughly 2% of customers on the E-32 S and E-32 M customers will be moved to the next largest tariff and roughly 10% of the E-32 S, E-32 M, and E-32 L customers will be moved to the next smallest tariff. Further, there is not a discernable trend between customer that will move up or down tariff and the load factor of the customer. Figures 26, 27, and 28 below contain scatter plots of customer's average summer demand and load factors. Those that are moving to a larger tariff are shown in blue, with those moving to a smaller tariff are shown in orange.

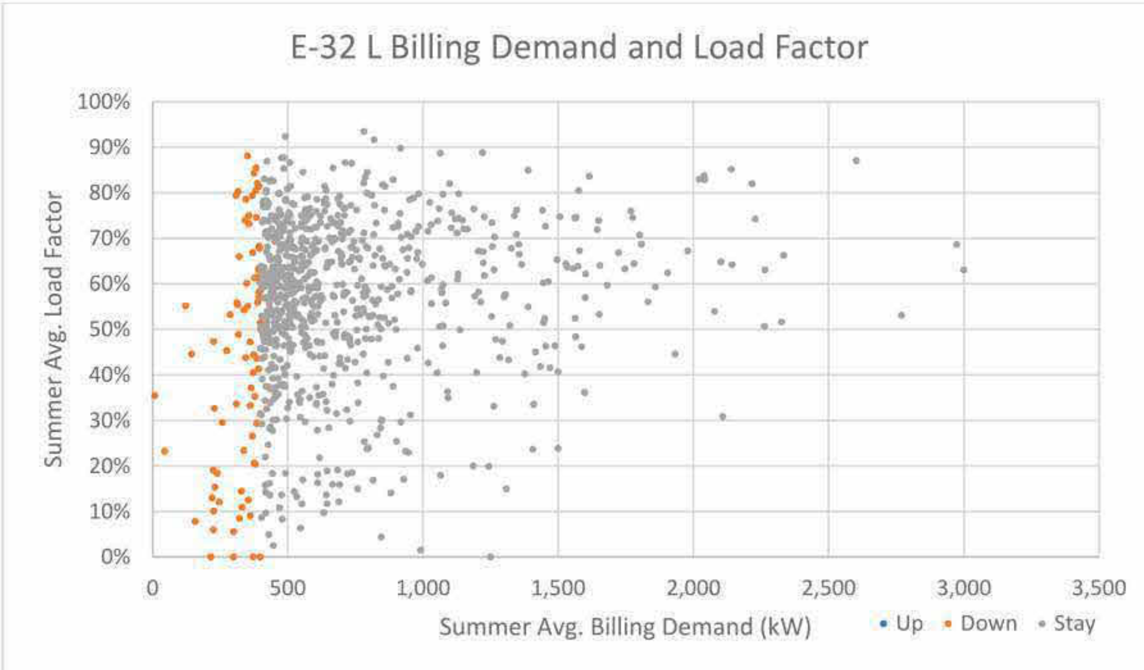


Figure 26 - E-32 L Billing Demand and Load Factor

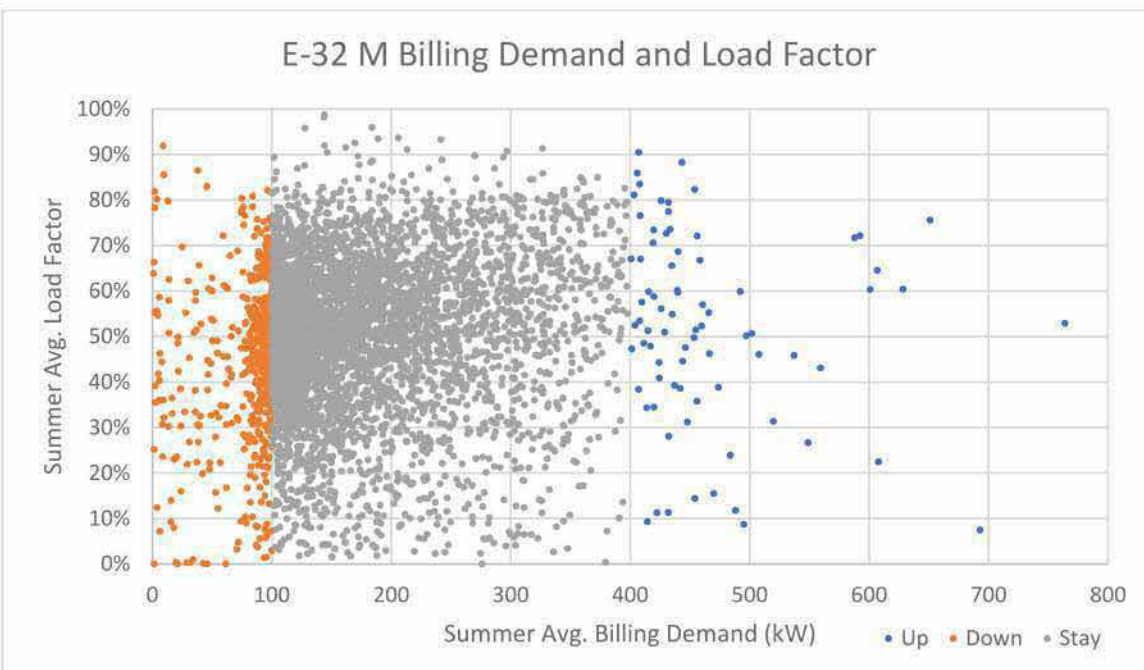


Figure 27 - E-32 M Billing Demand and Load Factor

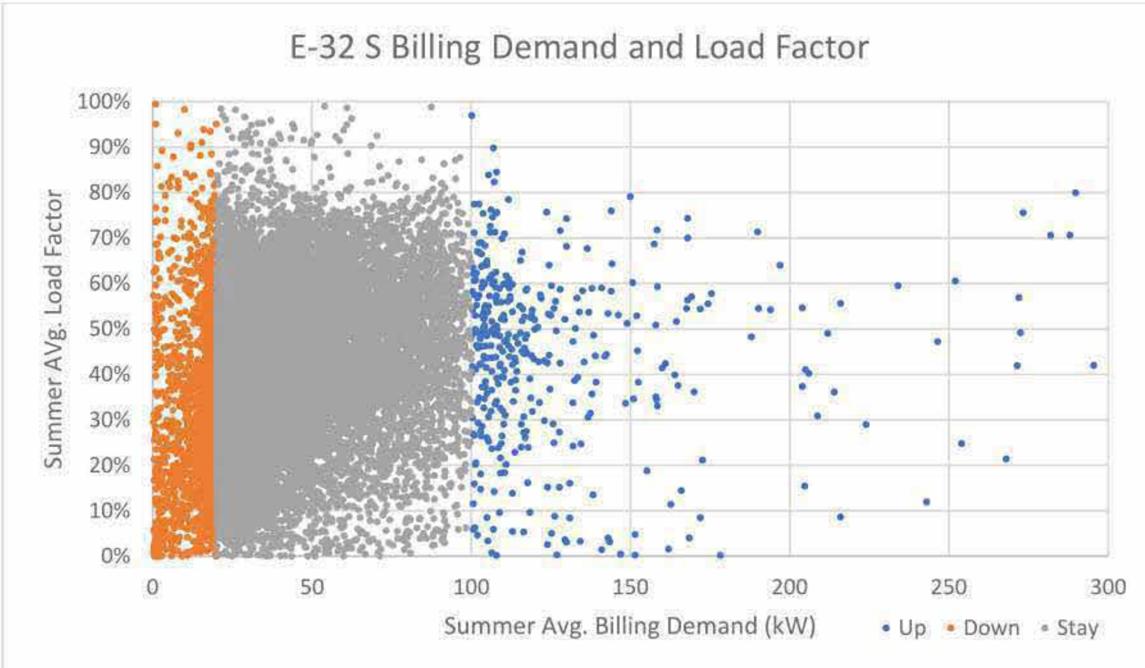


Figure 28 - E-32 S Billing Demand and Load Factor

Q184. FOR A CUSTOMER THAT IS CLOSE TO THE BORDER BETWEEN TWO TARIFFS, WHAT INCENTIVES DO THE RATES PROVIDE WHEN IT COMES TO SWITCHING BETWEEN TARIFFS?

A184. Generally, for customers that are between two tariffs, low load factor customers are better off on the smaller tariffs while high load factor customers are better off on the larger tariff. For instance, a customer on the E-32 L tariff with 401 kW of summer billing demand and a 30% load factor could save almost $5,000 or 3.3% of their annual non-BSC bill by dropping to 399 kW and using the same amount of energy on the E-32 M tariff. However, a customer with the same demand change but a 75% load factor would face an increase of nearly $12,000 or 5.4% on their annual non-BSC bill if they were moved to the smaller tariff.

A similar situation plays out with customers near 20 kW. A customer with 21 kW on the E-32 S tariff with a 30% load factor would see a savings of about $650 or 7.6% on their annual non-BSC bill if they dropped to 19 kW with the same amount of energy usage. But a customer with a 75% load factor would see an increase of about $1,000 or 7.9% on their annual non-BSC bill.

Q185. WHAT DO YOU RECOMMEND REGARDING THIS ISSUE?

A185. I recommend that the Commission direct the Company to investigate and implement rate designs that smooth transitions between the various non-residential tariffs and lessen the disincentive for any customer to reduce load. It is not good policy for a high load factor customer to artificially increase their demand in the summer just to avoid dropping to a rate that will increase their bills, just as it is not good policy to substantially increase the bills of low load factor customers when the move up in tariff class. This issue can be addressed by removing the declining block structure.

The Demand Ratchet on the E-32 L Tariff Should be Removed

Q186. WHAT IS A DEMAND RATCHET?

A186. A demand ratchet is a billing mechanism that places a floor under the billing demand of a customer. The ratchet floor is typically based on a fraction of the peak billing demand in single month in the past year and establishes the minimum amount of demand that a customer will be billed for even if their actual metered demand is lower. APS implements a demand ratchet on the E-32 L tariff at "80% of the highest kW measured during the six (6) summer billing months (May – October) of the twelve (12) months ending with the current month."[118] The E-32 L tariff measures the "highest kW" as the peak metered demand during a single 15-minute period at any time in the month.

Q187. WHAT IS THE THEORY BEHIND DEMAND RATCHETS?

A187. The theory is that customers, particularly large non-residential customers, are served by distribution infrastructure that has less load diversity than assets serving residential or small commercial customers. Because there is less load diversity, the equipment is sized closer to the sum of the non-coincident peaks of the customers served by the assets. Thus, if a customer has an unusually high peak demand level in a single month, but has low demand for

---

[118] Rate Schedule E-32 L.

other months, the theory suggests that absent a demand ratchet the customer will be under-contributing to revenue recovery for the assets that serve it.

Q188. WHAT FRACTION OF DISTRIBUTION SYSTEM COSTS IS ALLOCATED BASED ON THE CLASS DEMAND ALLOCATOR AND BASED ON THE INDIVIDUAL PEAK DEMAND ALLOCATOR?

A188. The Company allocates costs for its primary distribution system such as substations and primary overhead and underground lines based on the Class NCP. This allocator accounts for the load diversity found across the entire class. The costs for its secondary distribution system including line transformers are allocated based on the Individual Max allocator, which does not reflect load diversity. In total, 86% of General Service non-customer distribution costs are allocated based on the Class NCP, with only 14% based on Individual Max.[119] This suggests that there is load diversity in most of the distribution assets that serve even large commercial customers.

Q189. DOES APS APPLY THE E-32 L DEMAND RATCHET TO ALL OF ITS DEMAND-BASED BILLING COMPONENTS, OR JUST THE DISTRIBUTION DEMAND-BASED BILLING COMPONENT?

A189. It applies it to all demand-based billing components, including the generation and transmission components. This is problematic because, even if there is less load diversity on the distribution assets serving the individual customer, the generation and transmission infrastructure benefits from the load diversity of the entire customer base. Further, the demand ratchet is based on the individual customer non-coincident peak demand, which may or may not coincide with the system peak hours. If a customer happens to set their peak at 10 AM on a Saturday, this demand level has nothing to do with their contribution to generation and transmission demand costs which are driven by loads in summer afternoons. Simply put, there is no basis for applying a non-coincident peak demand ratchet to non-distribution billing components.

[119] LRS_WP11DR Cost of Service Study Model.

Q190. HOW OFTEN IS THE DEMAND RATCHET ACTIVATED?

A190. It is activated frequently. Based on E-32 L customer with 12 months of billing data, all customers had at least one month of ratcheted demand, and many had between 6 and 8 months of ratcheted demand. Figure 29 below shows the count of customers with a given number of months where they experienced a ratcheted demand.

Figure 29 - Months with Ratcheted Demand

Q191. WHAT OTHER DISINCENTIVES DOES THE DEMAND RATCHET PRODUCE?

A191. Demand ratchets produce a disincentive to reduce demand. If a customer sets their demand charge based on an unusually high 15-minute period, they are stuck with at least 80% of that demand level for a year. Any effort that a customer takes to reduce their demand below 80% of the peak value will not be rewarded in the following year. Further, a single bad 15-minute period in the following summer could reset the demand to a high level again, even if they had taken steps to lower their demand. This is overly punitive and could cost customers tens of thousands of dollars over the course of a year.

For customers who install energy storage systems to manage peak demand, a demand rachet can be very risky. A single slip during any 15-minute period over the entire summer can effectively lock out savings the remainder of the year. This is particularly troubling given the billing demand is based on a non-coincident peak. If the battery were offline at 2 PM in May, causing a customer to set their peak demand, there is no incremental cost to the system as a whole as there is plenty of excess capacity at that time. Nonetheless, that customer would have locked in their demand ratchet for the entire following year, meaning that most of the savings opportunities from installing storage are foregone for the following year.

Figure 30 below shows the impact of the demand ratchet on a hypothetical customer. This customer attains their peak demand of 578 kW in August, setting their demand ratchet of 462 kW for the following year. If this customer installed a storage system capable of reducing their demand by 20% or 116 kW, they could in theory have obtained demand reductions totaling 116 kW * 12 = 1,392 kW over the following year. However, because of the demand ratchet, the customer is only able to obtain savings of 287 kW, only 20% of the potential of the battery. The rest is lost to the demand ratchet.

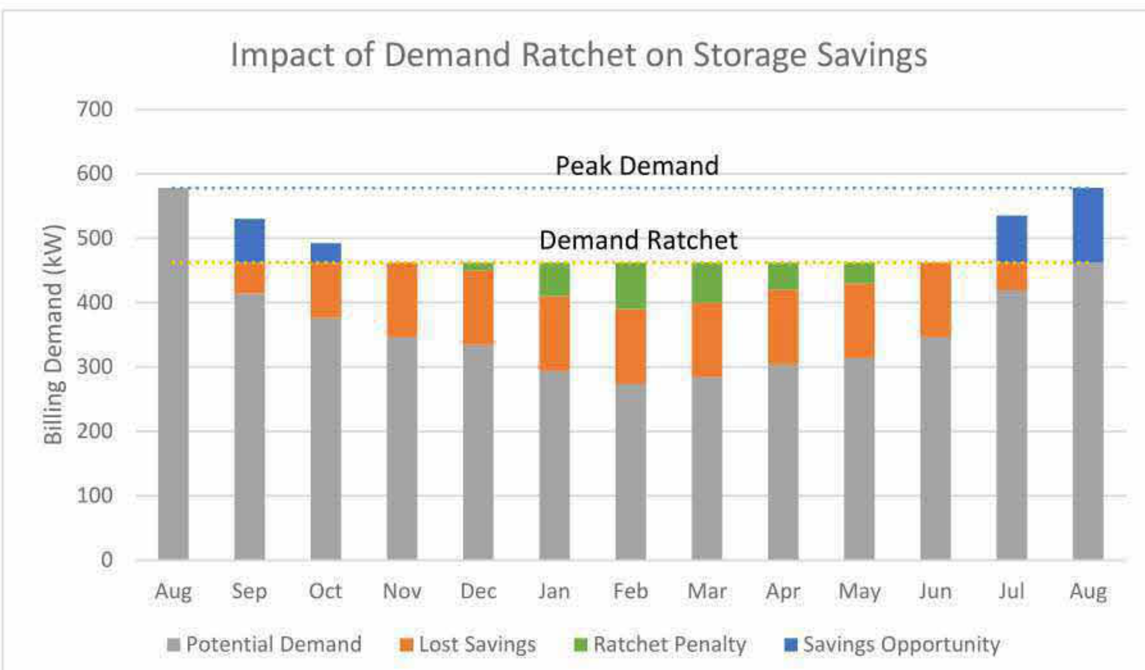


Figure 30 - Impact of Demand Ratchet on Storage Savings

Q192. WHAT DO YOU RECOMMEND WITH RESPECT TO THE DEMAND RATCHET?

A192. I recommend that the Commission require APS to remove the demand ratchet from the E-32 L tariff. The Company's CCOSS model accounts for substantial load diversity in cost allocation for the assets that serve non-residential customers, even large residential customers. Penalizing customers for an aberrant 15-minute demand reading for an entire year is simply too harsh. It provides a disincentive for load reduction or peak demand management, and discourages customers interested in installing battery storage systems.

If the Commission does not wish to remove the demand ratchet entirely, I recommend that it be lowered substantially to 50% to more accurately reflect the load diversity that exists on the distribution system serving larger commercial customers. I also recommend that it only be applied to the distribution portion of the bill and not be applied to the generation or transmission demand charges as those assets benefit from the full load diversity of the customer base.

The Declining Block Structure Should be Eliminated

Q193. WHAT IS A DECLINING BLOCK STRUCTURE IN RATE DESIGN?

A193. A declining block rate design charges an initial level of usage at one rate and additional usage at a lower rate. For the Company's E-32 S, E-32 M, and E-32 L tariffs, there is a declining block structure for demand charges with a breakpoint of 100 kW. For the E-32 S and E-32 M, there is also a declining block structure on energy charges with the breakpoint set at 200 kWh per kW. The E-32 XS has a seasonal declining block where usage under 5,000 kWh per season is charged at a higher rate than usage over 5,000 kWh per season.

Demand and energy rates fall by roughly 40% on the E-32 S and E-32 M rates while demand rates fall by roughly 30% on the E-32 L rate. Curiously, the demand-based tariffs have the same demand breakpoint of 100 kW despite the large variation in customer sizes that each tariff serve.

Q194. WHAT ECONOMIC INCENTIVE DOES THE DECLINING BLOCK STRUCTURE PROVIDE?

A194. On the energy charges, it provides an incentive to increase the load factor for a customer. Customers that have a load factor of roughly 27% or higher will use more than 200 kWh per kW per month.[120] These customers will see a discount on additional energy if they increase energy use without raising their demand, resulting in an lower average energy rate for a month.

However, the declining block structure for demand charges does not provide the same incentive as with the energy rates. In fact, it provides the oppose incentive; the marginal benefit of reducing demand is lower than the average rate that a customer pays for that demand. For customers that are around the 100-kW threshold, this can make a sizable difference. A customer on the E-32 S tariff reducing demand from 95 kW to 90 kW will see a benefit of $61 per month or $737 per year, but a customer on the E-32 M tariff reducing demand from 110 kW to 105 kW will see savings of only $34 per month or $402 per year. The 45% drop in savings can make a material difference to the customer when considering whether to invest in demand side management solutions.

Further, there is no difference to the overall system from a customer who reduces their demand from 95 kW to 90 kW or one who reduces their demand from 110 kW to 105 kW – both produce identical demand reductions. There is no justification for compensating one customer so much more than the other for the same demand reduction.

Q195. HOW DOES THE USE OF A CONSTANT 100 KW BREAKPOINT IMPACT CUSTOMERS ON THE VARIOUS TARIFFS?

A195. As compared to a flat or inclining block structure, the declining block provides less incentive to reduce demand and favors customers at the high end of the load range. Table 12 shows the equivalent flat rates for each class based on the average demand revenue collected on the tariff.[121]

---

[120] Consider a customer with a 10 kW of billing demand that uses 2,000 kWh in a month. Their approximate load factor will be 2,000 / (10 * 8760 / 12) = 27.4%

[121] JEH-WP1DR Proof of Revenue

	E-32 XSD	E-32 S	E-32 M	E-32 L	E-34
Eligible Demand (kW)	0 – 20	21 - 100	101 - 400	400 - 3,000	3,000+
Demand Rates (Secondary)					
First 100 kW	$7.703	$11.530	$12.280	$25.704	$22.082
Add'l kW	$7.703	$6.702	$7.004	$17.812	$22.082
Average Rate	**$7.703**	**$11.470**	**$9.908**	**$19.004**	**$22.082**

Table 12 - Average Demand Rates

Customers on the E-32 S (21 – 100 kW) will face the higher initial demand block of $11.53 / kW for nearly all of their usage. E-32 M (101 – 400 kW) will face an average demand rate that declines as demand increases. Those closer to the lower size range of 101 kW will see a rate closer to the initial block of $12.28 / kW while those at the high range will experience an average rate closer to $8.30 / kW. Customers on the E-32 L rate (401 – 3,000 kW) have demand well in excess the 100-kW breakpoint, so their average rate starts close to the marginal rate of $17.81 / kW and slowly declines as load increases.

Figure 31 below shows the result of these tariff structures on the collection of revenue.[122] For the most part, smaller customers are served on tariffs that collect more revenue from energy than demand. The E-32 XS tariffs collect a disproportionate amount of revenue through fixed charges compared to the other tariffs, with the E-32 XSD collecting a sizable 27% of total revenue through a fixed charge.

[122] JEH-WP1DR Proof of Revenue

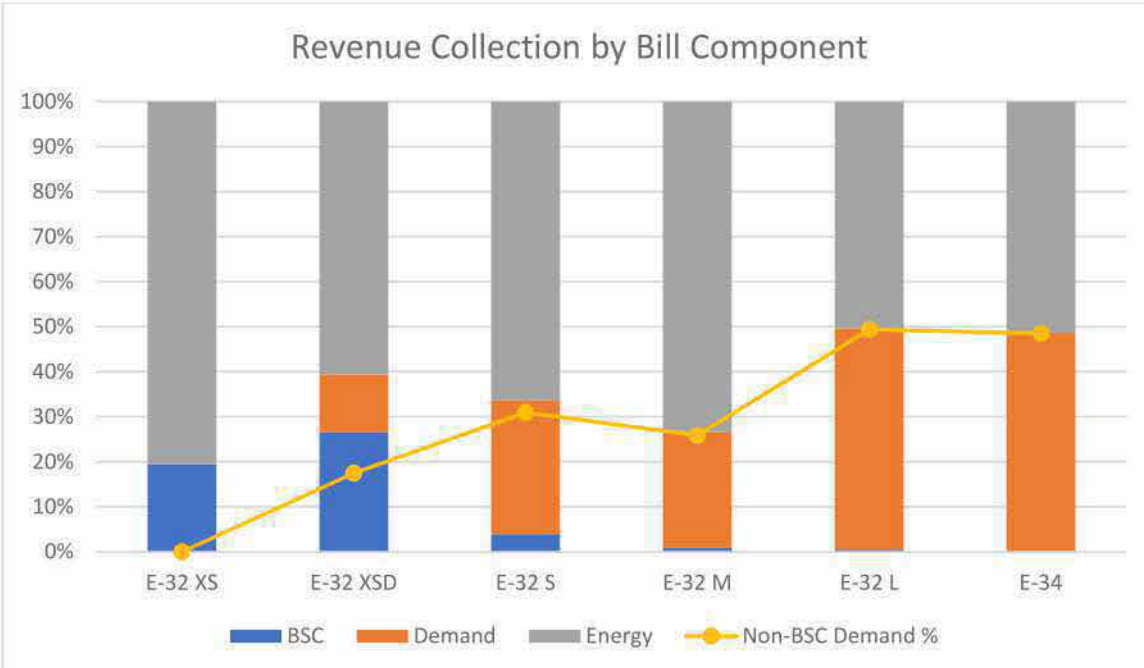


Figure 31 - Revenue Collection by Bill Component

There is a break in the trend of energy/demand balance on the E-32 S tariff. Customers on the E-32 XSD tariff pay 17% of their non-BSC bill through demand charges while those on the E-32 M pay 26%. One would expect customers on the E-32 S tariff to pay somewhere in between these values, but instead they pay more through demand charges than the E-32 M class at 31%. This is a direct result of the use of a constant 100-kW breakpoint for all of the tariffs regardless of customer demand ranges. Nearly all demand on the E-32 S is billed at the higher initial rate, while more demand on the E-32 M is billed at the lower marginal rate.

Q196. WHAT DO YOU RECOMMEND WITH REGARD TO THE DECLINING BLOCK STRUCTURE?

A196. I recommend the Commission require the Company to remove the declining block structure from its tariffs to help encourage energy and demand savings for all customers regardless of their usage. Compared to using either marginal costs or even using average costs to set demand, the Company's current rate structures provide misaligned incentives. The energy rate encourages more energy consumption at a given demand level by providing a discount to incremental usage. At the same time, the demand rate reduces the incentive to decrease demand for customers over the 100-kW threshold compared to using an average demand rate.

I also recommend that the Company rebalance the E-32 S rate to collect less non-BSC revenue through a demand charge and more through an energy charge by setting the demand rate in between the E-32 XSD and E-32 M rates at $8.805 / kW. This would result in 23% of non-BSC revenue from demand charges, falling neatly between the 17% on the E-32 XSD and 26% on the E-32 M.

Finally, I recommend the declining block energy rates also be removed. While encouraging high load factors is a laudable goal, this is already done through the presence of demand charges. Adding an additional incentive to use more energy at a given level of demand through a lower rate is contrary to energy efficiency efforts.

The Company's Energy Storage Pilot Program Tariff Requires Modifications

Q197. PLEASE DESCRIBE THE COMPANY'S BATTERY STORAGE PILOT PROGRAM TARIFF.

A197. The Company offers tariff E-32 L SP "Large General Service (401+ kW) Storage Pilot" for customers that have an average summer load of 401 kW or greater and have installed an energy storage system that is able to reduce summer on-peak demand by 20%.[123] The tariff itself is very complex, containing three TOU periods that vary by season, an "excess off-peak" demand measure, and a very high BSC.

Q198. WHAT WAS THE ORIGIN OF THE E-32 L SP RATE?

A198. Parties were not able to negotiate a resolution to several issues related to the E-32 L tariff in the case that resulted in the Settlement, including those related to creating an optional rate to encourage energy storage systems. As a result, the Commission directed the Company to establish a "storage-friendly" rate that did not include a demand ratchet, off-peak demand charge, or a declining block demand charge. The Commission also dictated parameters such

[123] Rate Schedule E-32 L SP.

as the 6-hour peak period and excess off-peak calculation.[124] The E-32 L SP tariff is the Company's response to the Commission directive, and was "patterned after a similar rate for Tucson Electric Power."[125]

Q199. HOW DO THE E-32 L TARIFF VARIATIONS COMPARE?

A199. Table 13 below compares the structure of the E-32 L, the E-32 L TOU, and E-32 L SP tariffs. All figures are based on the Company's proposed rates for secondary customers in this proceeding. The rates are rather complex, but generally, the E-32 L TOU recovers more revenue through energy charges than the other tariffs. The E-32 L tariff revenue recovery is about 50% from energy, 49% from demand, and 1% from BSC. The E-32 L TOU tariff splits about 59% from energy, 40% from demand, and 1% from BSC.[126]

[124] Decision 76295 at 106, Docket No. E-01345A-16-0036
[125] Attachment KL-47, SEIA 27.1.
[126] JEH-WP1DR Proof of Revenue

Component	E-32 L	E-32 L TOU	E-32 L SP
Seasons			
Summer	May – Oct	May – Oct	June – Sept
Non-Summer	Nov – Apr	Nov – Apr	Oct – May
TOU Periods			
On-Peak	N/A	3 – 8 PM Weekdays	**Sum**: 2-8 PM **NS**:4-10 PM
Remainder	N/A	N/A	**Sum**: 11 AM – 2 PM 8 PM 11 PM **NS**: 6-10 AM, 3-4PM, 10-11 PM
Off-Peak	N/A	Others	Others
BSC ($/Day)	$3.997	$3.997	$28.185
Demand ($ / kW)			
Summer Peak / Remaining			$24.346
First 100 kW	$25.704	$17.708	
Add'l kW	$17.812	$11.903	
Summer Off-Peak / Excess			$18.290
First 100 kW	$25.704	$6.486	
Add'l kW	$17.812	$3.411	
Non-Summer Peak / Remaining			$21.284
First 100 kW	$25.704	$17.708	
Add'l kW	$17.812	$11.903	
Non-Summer Off-Peak / Excess			$15.993
First 100 kW	$25.704	$6.486	
Add'l kW	$17.812	$3.411	
Energy ($ / kWh)			
Summer	$0.05649		
On-Peak		$0.07147	$0.04900
Remainder			$0.04597
Off-Peak		$0.05846	$0.04092
Non-Summer	$0.03802		
On-Peak		$0.05667	$0.04496
Remainder			$0.04245
Off-Peak		$0.04366	$0.03587

Table 13 - E-32 Variant Rate Designs

Unlike all the Company's other tariffs, the summer season on the E-32 L SP is June to September, with the non-summer rate in effects from October to May. The tariff has a longer 6-hour peak of 2 PM to 8 PM in the summer and 4 PM to 10 PM in non-summer months compared to a constant 5-hour peak of 3 PM to 8 PM weekdays. The off-peak period is twelve hours (11 PM to 11 AM in the summer, 10 AM to 3 PM and 11 PM to 6 AM in non-summer), with the balance of six hours designated as the "remaining" or intermediate TOU period. The "excess off-peak" is defined as off-peak demand that is in excess of on-peak demand by more than 150%. Essentially, off-peak demand that falls within 150% of the on-peak demand does not incur any cost to the customer, but any demand over this amount is charged at the off-peak excess demand rate.

For secondary distribution customers, the summer on-peak and remaining periods are priced at $24.346 / kW, with the off-peak excess demand at $18.290 / kW. In the non-summer period, the rates change to $21.284 / kW for on-peak and remaining and $15.993 / kW for off-peak excess. These demand rates are substantially higher than the demand rates on the other E-32 L variations, particularly considering the marginal demand cost is much lower on the declining block rates. There is a $28.185 / day BSC for taking service through instrument-rated meters, which amounts to $10,288 per year, almost $9,000 more than the annual BSC of $1,459 on the E-32 L tariff.

Q200. WHAT CHANGES IS THE COMPANY PROPOSING TO THE E-32 L SP TARIFF IN THIS DOCKET?

A200. Yes, the Company is proposing two changes. The first is to decrease the calculation of excess off-peak demand from 200% of on-peak demand to 150% of on-peak demand. This change is less favorable for customers on the tariff but does comport with the Commission's directive in the Settlement Order. The second change is to exclude the E-32 L SP tariff from the Lost Fixed Cost Recovery Mechanism ("LFCR") adjustment schedule.

Q201. WHAT SHOULD BE THE OVERRIDING DRIVER OF RATE DESIGN FOR CUSTOMERS INSTALLING STORAGE OR SOLAR PLUS STORAGE SYSTEMS?

A201. The goal should be to maximize incentives for customers to reduce their demand during hours that coincide with the system peak. It is important that a rate provide an incentive to maximize utilization of the battery during these peak-aligned hours and not solely focus on managing the demand of the customer in every hour. Driving peak-coincident reductions will help reduce current energy costs (by reducing the need for expensive energy and avoiding marginal line losses) and reduce future capacity needs (by delaying or deferring the need to construct new capacity to serve peak demands).

Tariffs with non-coincident demand measurements, such as the base E-32 L, encourage customers to use storage systems to minimize their own load regardless of whether it is aligned with the system peak. This creates a perverse incentive where a customer could save money by shifting load into peak hours (which increases costs for everyone on the system) when minimize their own peak demand during non-peak hours.

Q202. THE COMPANY PREVIOUSLY ARGUED THAT INCENTIVES FOR ENERGY STORAGE SHOULD BE PROVIDED THROUGH MEANS OTHER THAN RATE DESIGN, SUCH AS DIRECT INCENTIVES. HOW DO YOU RESPOND?

A202. The Company previously proposed a $2 million program that would pay for 50% of an individual storage system cost not to exceed $100,000, voicing preference for this program rather than incentives "buried in rate design."[127] While up-front incentives can be useful in spurring projects, there still needs to be economic value in the rate itself to send appropriate signals as to when to charge and discharge the system.

NREL published an excellent report titled "An Overview of Behind-The-Meter Solar-Plus-Storage Regulatory Design" that discusses some of the policy design challenges for energy storage and solar plus storage systems.[128] It correctly notes that rate design is a vital part of any policy construct:

> Retail tariff design is an essential element of compensation mechanisms for [distributed PV] DPV-plus-storage systems. From a customer's standpoint, the bill savings and credits yielded from behind-the-meter systems are intrinsically linked to retail tariff design and, thus, retail tariffs strongly influence both customer economics and deployment. From a utility's perspective, retail tariff design can promote utility revenue sufficiency and help align customers' exports and consumption with the needs of the larger power system…
>
> **Tariff design is the primary tool to align the interests of DPV-plus-storage customers with the broader power system.** Relative to grid-tied DPV systems, the

[127] Decision 76295 at 71-72, Docket No. E-01345A-16-0036.

[128] *An Overview of Behind-The-Meter Solar-Plus-Storage Regulatory Design, Approaches and Case Studies to Inform International Applications*, National Renewable Energy Laboratory and USAID, March 2020. Available at https://www.nrel.gov/docs/fy20osti/75283.pdf

> presence of a paired behind-the-meter storage system allows customers to better control the magnitude and timing of their electricity consumption from the grid, as well as their grid exports. TOU volumetric energy rates and coincident demand-based charges, if designed and implemented properly, can take advantage of this load shifting capability and incentivize DPV-plus-storage customers to act in a more grid-optimal manner (e.g., reducing consumption and/or increasing exports during typical peak demand periods). This behavior, as incentivized by time-variant tariffs, can help ease the management of DERs on the distribution system and also lead to a reduction in power system operational costs. Implementation of such tariffs may require new metering equipment and administrative responsibilities for utilities but can serve as a grid-friendly incentive for customers to install DPV-plus-storage systems.[129]

One cannot ignore the role that rate design plays in providing incentives or disincentives for both the installation and operation of energy storage systems. The Company's previous position to offer a one-time incentive while not adjusting rate design will likely not result in as robust of an energy storage deployment. Further, rates that work counter to the interest that the incentive is designed to support result in a need to pay a higher incentive in the first place. Ideally, the rates should first be designed appropriately before any incentive is considered.

Q203. ARE CUSTOMERS ON THIS RATE ELIGIBLE FOR NET METERING?

A203. Yes. Customers may install solar and are eligible for the EPR-6 rider for net metering.

Q204. ARE THERE ADVANTAGES TO PAIRING ENERGY STORAGE WITH SOLAR AS COMPARED TO INSTALLING STANDALONE STORAGE?

A204. Yes. Currently, installing energy storage along with solar makes the energy storage system eligible for the federal ITC, which is currently 26% of capital costs. Additionally, storage must be primarily charged from the solar system to retain ITC eligibility. Storage that is charged 100% from the solar system is eligible for a 5-year accelerated depreciation and the full ITC. Storage that is charged between 75% and 99% from the solar system is eligible for 5-year accelerated depreciation and a fraction of the ITC equal to the solar charging level.[130] Storage that is charged with less than 75% from solar is not eligible for the ITC but does

---

[129] Id. at v. (emphasis added)

[130] For example, if a system is charged with 80% solar, it qualifies for 80% of the current ITC.

qualify for 7-year accelerated depreciation, the same incentive available to standalone storage.[131]

Given that most of the lifecycle costs of energy storage are in the form of capital costs, the availability of the ITC when pairing with solar provides a powerful incentive to the market. As such, most developers installing behind-the-meter storage are also installing solar. Additionally, pairing solar and storage allows a customer to ride through a broader grid outage for a longer time than can standalone storage as the battery has an energy source to recharge.

Q205. DID YOU FIND A POTENTIAL ISSUE IN YOUR ANALYSIS OF THIS RATE?

A205. Yes. In seeking to understand how customers would fare on the E-32 L variations, I downloaded hourly load data for several commercial buildings from the Department of Energy Office of Energy Efficiency and Renewable Energy data set.[132] Using the National Renewable Energy Laboratory's ("NREL") System Advisor Model ("SAM"), I modeled the impact of installing solar and solar plus storage on the various tariffs.[133] However, before I was able to draw conclusions about the various rates, I noticed that the bill without any solar or storage was higher on the E-32 L SP rate than on the E-32 L or E-32 L TOU.

Table 14 below shows the results for the Large Office, Hospital, and Large Hotel reference buildings located in the Phoenix area.[134] The Large Office had an annual peak load of 1,687 kW, annual usage of 7,646,295 kWh, and a load factor of 51.7%. The Hospital had an annual peak load of 1,576, annual usage of 10,129,385 kW, and a load factor of 73.4%. The Large Hotel had a peak load of 501 kW, annual usage of 2,717,607 kWh, and a load

---

[131] Federal Tax Incentives for Energy Storage Systems, National Renewable Energy Laboratory. Available at https://www.nrel.gov/docs/fy18osti/70384.pdf

[132] Hourly load profiles are available for 16 commercial building types based off the DOE commercial reference building models. Files were downloaded for Phoenix, AZ and are available at https://openei.org/datasets/files/961/pub/COMMERCIAL_LOAD_DATA_E_PLUS_OUTPUT/USA_AZ_Phoenix-Sky.Harbor.Intl.AP.722780_TMY3/

[133] SAM allows a user to enter an hourly load profile and a utility rate design, and then configure a solar or solar plus storage system to analyze the impact on the customer's bill. It is available at https://sam.nrel.gov/download.html

[134] This calculation is based only on the tariff rates and does not include riders or adjustment clauses.

factor of 61.9%. All buildings have loads that fit squarely within the E-32 L tariff. The excess off-peak demand rate was set to $0 / kW in the E-32 L SP tariff in this analysis.

	E-32 L	E-32 L TOU	E-32 L SP
Large Office			
BSC	$1,459	$1,459	$10,288
Energy	$372,909	$421,154	$321,317
Demand	$352,363	$301,526	$427,192
Total	**$726,731**	**$724,139**	**$758,797**
Delta over Min	**$2,592**		**$34,658**
Delta %	**0.4%**		**4.8%**
Hospital			
BSC	$1,459	$1,459	$10,288
Energy	$477,589	$538,170	$418,373
Demand	$336,614	$291,140	$409,416
Total	**$815,662**	**$830,769**	**$838,077**
Delta over Min		**$15,107**	**$22,415**
Delta %		**1.9%**	**2.8%**
Large Hotel			
BSC	$1,459	$1,459	$10,288
Energy	$130,045	$146,444	$124,802
Demand	$108,908	$94,966	$114,236
Total	$240,412	$242,869	$249,326
Delta over Min		**$2,220**	**$8,667**
Delta %		**0.9%**	**3.6%**

Table 14 - E-32 L Variant Bill Analysis

While the Large Office performed slightly better than the Hospital or Large Hotel on the TOU rate due to its relatively lower on-peak usage, the E-32 L and E-32 L TOU rates produced similar results – albeit with a different ratio of energy and demand cost – that are expected from a revenue-neutral rate. In all three cases, the customer fared worse on the E-32 L SP rate, with the Large Office seeing a 4.8% increase over the E-32 L TOU rate and the Hospital and Large Hotel seeing a 2.8% and 3.6% increase, respectively, over the E-32 L rate.

Q206. YOUR RESULTS ARE FOR CUSTOMERS WITHOUT ANY SOLAR OR STORAGE. WHY IS THAT A VALID COMPARISON FOR A RATE DESIGNED TO INCENT STORAGE?

A206. Because no customer would make a rational decision to switch to a tariff that increases their post-system bill even if it means the solar or storage system can save relatively more money on that tariff. Rather, the customer will compare the bill on either the E-32 L or E-32 L TOU without a system to the bill on the E-32 L SP with a system. Unless the savings from the system exceeds the bill increase already embedded in the rate resulting in a lower overall bill on the E-32 L SP tariff, the customer will not switch to this rate.

In the example above, the energy storage system doesn't just have to save money, it has to overcome the higher costs embedded in the E-32 L SP tariff. For the Large Office customer, the storage system would have to provide savings of nearly $35,000 per year just to make up for the change in tariff. Savings that actually pay for the battery would need to be incremental to this figure.

Q207. HOW MANY CUSTOMERS HAVE SIGNED UP FOR THIS RATE?

A207. None. Despite having been in place for nearly three years, not a single customer has signed up for the E-32 L SP tariff.[135] Further, the TEP tariff after which the E-32 L SP was modeled also has zero customers.[136] It is clear from the total failure of these tariffs to attract customers that they are not designed appropriately and must be modified.

Q208. WHAT CHALLENGES DOES THE E-32 L SP TARIFF PRESENT FOR THE ECONOMIC DEPLOYMENT OF STANDALONE STORAGE AND SOLAR PLUS STORAGE SYSTEMS THAT MAY EXPLAIN THE TOTAL LACK OF CUSTOMERS?

A208. There are several elements of the tariff that would be challenging to meet through a system that is attempting to maximize the ITC by charging exclusively with solar. Requiring a 20% demand reduction to even qualify for the tariff puts immediate constraints on a customer

[135] Attachment KL-48, SEIA 27.2.

[136] *Notice of Filing - Tucson Electric Power Company's Large General Service Time-of-Use Storage Program Informational Filing Docket No. E-01933A-15-0239 and E-01933A-15-0322.* Available at https://docket.images.azcc.gov/E000007953.pdf

wishing to pair their system with solar. The Large Office customer above would require a peak load reduction of roughly 300 kW, which would require a PV system of at least 300 kW to charge a four-hour duration system prior to the on-peak window, and an even larger PV system to charge a longer-duration battery. It is highly unlikely that the office will have a roof space large enough to support this system size. If the tariff is well designed, there is no need to require a minimum level of demand reduction.

The six-hour peak TOU period is longer than the typical four-hour design for behind-the-meter ("BTM") batteries. Whether for standalone storage or solar plus storage, although six hours of storage can be accommodated, it would increase the cost of the system. Further, the operational complexity involved in reducing demand by a minimum 20% across six hours is higher than reducing it in four or five. As shown above in Figure 9, the top four hours between 2 PM and 6 PM capture the vast majority of high load hours during the core summer months. This extends to the non-summer periods as well; the absolute level of system demand is much lower in the non-summer months, so creating a longer peak period is unnecessary to drive load reductions that lead to system cost reductions.

The equivalence of the on-peak and remaining TOU period demand charges is also a problem. If a customer were to shift their load away from the peak period, some of it would likely fall into the remaining hours. Because there is no cost differential between these two periods, the amount a customer saves by reducing demand by 1 kW on peak will be given up by increasing remaining hour demand by 1 kW. Similarly, requiring customers to actively manage their demand for 12 hours a day (peak and remaining) rather than just 6 hours a day (peak) will require systems to be managed more conservatively during peak hours. This needlessly reduces the incentive for storage systems to drive system-coincident reductions.

For storage systems that must be charged from solar, the onset of the remaining hours at 11 AM in the summer may not allow sufficient time for the battery to fully charge. This may in turn increase the customer's demand during the morning remaining period of 11 AM to 2 PM as the PV system charges the battery in preparation for use during the on-peak period rather than reducing load. During the non-summer months, there is a better opportunity to charge during the 10 AM to 3 PM off-peak hours, but the charge must then be rationed over 12 peak and remaining hours before another off-peak charging opportunity.

The energy rates have a very small differential on the E-32 L SP rate. The on-peak to off-peak differential is only 0.8 cents / kWh during summer and 0.9 cents / kWh during non-summer. These is 40% and 30% smaller than the summer and non-summer spreads on the E-32 TOU rates. The on-peak to remainder differential is even smaller, netting only 0.3 cents / kWh in the summer and 0.25 cents / kWh in the non-summer. While the batteries can realize savings from demand charge management, the very low energy spread severely reduces the savings from shifting energy from peak to off-peak.

Q209. HOW COULD THIS TARIFF BE IMPROVED TO HELP SUPPORT STORAGE AND SOLAR PLUS STORAGE PROJECTS?

A209. I suggest the Commission adjust its pilot program guidelines to allow the Company to design a rate that will better align with the current state of the BTM storage market. This modified rate can provide encouragement that drives solar plus storage or standalone storage reductions during peak hours that will provide cost savings to all of APS's customers. The first change should be the elimination of the 20% peak demand reduction requirement. This minimum reduction may immediately disqualify customers seeking to install solar plus storage systems due to the lack of roof space. The Company should be ambivalent whether it attains the same demand reduction from more customers.

Aside from this, I recommend the on-peak period be reduced from six hours to five or preferably four hours. This will help reduce the cost of a system that can be cost-effective installed under this tariff by reducing the duration needed to meet the peak load reduction parameter. These hours should be well aligned with the bulk power system loads to ensure that demand reductions from individual customers benefit the system writ large.

I also recommend the Company create a reasonable differential between the on-peak and remaining hour demand rate; setting these rates equal creates the equivalent of a twelve-hour peak in the summer and an eight-hour peak in the non-summer months. The E-32 L SP pricing should reflect the cost-drivers on the system. Load during non-peak hours when there is spare capacity does not drive costs.

The combination of these actions should be coupled with a sufficient time period to enable solar to fully charge the battery. Common non-residential solar plus storage system configurations include a battery that is sized at 30-50% of the kW rating of the PV system with two to four hours of storage. At the high end, this will require at least two hours at full PV output to completely charge from solar, during which the demand charge should be sufficiently low to incent charging as opposed to demand management.

Together, these changes will increase the likelihood that non-residential customers can economically develop standalone storage and solar plus storage systems. This in turn will produce more tools to manage load growth and help accelerate the Company's transition to a zero-carbon future.

Q210. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FROM THIS SECTION OF YOUR TESTIMONY.

A210. I recommend the Commission require the following changes to the Company's non-residential tariffs:

- Remove the declining block structure for both energy and demand rates on the E-32 rates
- Remove the demand ratchet from the E-32 L tariff
- Reduce the demand charge on the E-32 S tariff to $8.805 / kW to reduce the balance of revenue recovery through demand charges to be in between the E-32 XSD and E-32 M tariffs
- Better align the "edges" between tariffs to prevent large rate shocks and disincentives for high load factor customers to reduce their demand
- Make several changes to the storage pilot guidelines that led to the E-32 L SP tariff
    - Eliminate the 20% peak demand reduction
    - Reduce the on-peak period to 4 hours
    - Create a reasonable differential between the on-peak and remaining hour demand rate
    - Increase the differential in the energy rates
    - Allow sufficient time for storage systems to be fully charged by solar

VII. "BRING YOUR OWN DEVICE" PROGRAM DESIGN CONSIDERATIONS

Q211. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A211. In this section, I propose the adoption of a "Bring Your Own Device" ("BYOD") tariff program. I also respond to Commissioner Peterson's July 16, 2020 information request related to BYOD tariffs and incentives that utilize distributed energy resources ("DERs"), and distributed solar and storage systems in particular.[137]

Q212. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A212. BYOD programs have the potential to cost-effectively leverage DERs, including batteries, to provide grid services and defer capacity upgrades. If designed correctly, BYOD programs can save all customers money while increasing the flexibility of the distribution grid to accommodate load growth and an increasing penetration of customer-sited DERs.

The Stage is Set for a BYOD Program

Q213. WHAT IS THE PURPOSE OF A BYOD PROGRAM?

A213. A BYOD program is designed to meet identified grid needs within distribution, transmission, or bulk system domains through the use of customer-sited distributed resources rather than through traditional utility investments. The program is designed to target locational and temporal needs; that is, capacity or grid service requirements that are located in a specific place that can be addressed at a specific time. These programs can leverage the Company's existing customer base to develop these services at a lower cost than constructing new utility assets. If insufficient resources exist, a market-based process can attract new DER resources to provide the services. BYOD programs often involve a third-party service aggregator that coordinates response from hundreds or thousands of residential customers.

SEIA and AriSEIA member Sunrun has been actively involved in BYOD program design and development in California, New York, and New England. Sunrun has proposed a tariff-based program design that would allow utilities to cost-effectively leverage new and

[137] https://docket.images.azcc.gov/E000007643.pdf

existing DERs to help defer new capacity upgrades and manage the real-time operation of the grid safely and reliably. More information on Sunrun's proposal can be found in their comments to the Public Utility Commission of the State of California, which I have attached as an exhibit to my testimony.[138]

Q214. WHAT ARE THE PREREQUISITES FOR A SUCCESSFUL BYOD PROGRAM?

A214. The utility must have an identifiable need for new distribution capacity and services, either due to expected load growth, to accommodate growth in DERs, or to increase flexibility on the distribution grid to help manage intermittent resources on the bulk power system. APS has all three. It projects consistent load growth for the foreseeable future; has a customer base that has demonstrated interest in solar, storage, and electric vehicles; and has plans to dramatically increase the use of solar and wind to fuel its bulk power grid.

Another element that must also be present for a successful BYOD program is a robust distribution system planning process. This includes the need for enhanced visibility of the status of the distribution grid, detailed information about loads and usage on feeders, and an intentional planning process to provide distribution services without simply resorting to utility-built infrastructure. Fortunately, APS has implemented advanced metering infrastructure, a bedrock technology needed to provide insights to the status of the distribution grid. It must also continue to develop and broaden its distribution planning capabilities to identify distribution deferral and other grid services opportunities to fully realize the potential of a BYOD program.

Q215. WHAT TYPES OF CAPABILITIES CAN BYOD PROGRAMS PROVIDE?

A215. Generally, BYOD program capability can be divided into two groups. The first is utilizing DERs to defer location-specific or system-wide capacity needs. The second is using DERs to enhance the flexibility of the grid in response to real-time conditions. Under the first category, programs that aggregate demand response from programmable thermostats or

---

[138] Sunrun Inc. Proposal for Distributed Energy Resources Distribution Service Tariffs, Rulemaking 14-10-003. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M266/K859/266859811.PDF

energy storage systems can provide load reductions during hot summers to relieve stress on the bulk power grid. In a more sophisticated implementation, customers can be geographically targeted to provide distribution circuit-level reductions that not only benefit the bulk power grid but also help maintain the reliability of local distribution assets.

BYOD programs can also increase the ability of APS to flexibly respond to real-time grid conditions. By having granular control over individual distributed assets, service aggregators can provide targeted load management to help mitigate power quality issues or increase hosting capacity limits for specific feeders. If there is an unexpected increase in wind generation, an aggregator can direct DERs to soak up what would potentially be curtailed energy. Likewise, if a section of the grid experienced an outage that is putting stress on a neighboring feeder, DERs can be activated to help restore voltage levels and prevent further power quality or reliability issues.

BYOD peak demand reduction programs are demand response programs that operate on a utility forecasting and event-based dispatch model. Under this model, the utility uses load forecasting to predict upcoming peak events, and participating customers are notified that their batteries will be called upon for dispatch over the course of a particular event. At the appropriate time, the participating customers' batteries are dispatched in accordance with the operating parameters agreed to by each customer and the utility. This model allows the utility to forecast when the system peak will occur for a particular day, or week, or month and "call" upon the BYOD program resources to respond in a coordinated fashion over the peak event period. This provides the utility substantial certainty regarding the amount of peak reduction that will be achieved from the batteries enrolled in the program for any given event, and ensures the participating batteries are utilized to maximize their potential over the course of the event. This model also provides certainty and predictability to the customer about the timing, duration and use of their battery, and the compensation they will receive for performing during the event.

Q216. HAVE OTHER STATES IMPLEMENTED BYOD PROGRAMS?

A216. Yes. Several states have implemented programs that are designed to use the capabilities of DERs to meet new and changing distribution services. Programs that coordinate programmable thermostats are common, including one implemented by APS. A growing number of utilities have moved beyond control of HVAC systems into BYOD programs that incorporate DERs such as water heaters, solar, energy storage, and EV chargers.

National Grid in Massachusetts and Rhode Island has partnered with EnergyHub to create a BYOD program that integrates energy storage into demand response events.[139] By extending beyond a traditional thermostat program, the utility, aggregator, and individual customer can realize incremental benefits. The utility gets a larger base of flexible demand assets, the aggregator is compensated for providing a valuable service to the utility, and the customer contributes to demand response events more frequently with less personal impact.

The Massachusetts utilities are also seeking approval to turn their existing "daily dispatch" demonstration programs into full-scale programs under the Residential Storage Performance offering.[140] Based on the demonstration offerings, the utilities concluded "[t]he daily dispatch demonstrations performed as expected and delivered daily peak demand reductions in a reliable manner while minimizing customer comfort or productivity impacts" and that "there is sufficient evidence to support the wide-scale deployment of the daily dispatch pay-for-performance offering."[141] Under the daily dispatch program, events would be called based on forecasted daily summer system peak,

---

[139] https://www.energyhub.com/blog/national-grid-residential-battery-demand-response

[140] *See* Mass. Dept. of Pub. Utils, Docket Nos. 20-33 – 20-36, *Petition for Approval of Compliance Filings Regarding Implementation of Daily Dispatch Pay-for-Performance Offering* (each utility submitted separate petitions to implement the same program in each utility's service territory).

[141] *See* Mass. Dept. Pub. Utils., Docket No. 20-35, Pre-filed Testimony of Ezra J. McCarthey on behalf of National Grid at pp. 13-14 (Mar. 16, 2020); Docket No. 20-36, *Petition for Approval of Compliance Filings Regarding Implementation of Daily Dispatch Pay-for-Performance Offering* at p. 3.

between 2:00 PM and 7:00 PM; but on any particular day the called events would last no more than three hours.[142]

Vermont utility Green Mountain Power has a BYOD program that offers both utility- and customer-owned batteries that can be activated for demand response and shaping overall customer demand.[143] The batteries provide multiple services to multiple parties, including backup power to customers and demand flexibility to the utility to both increase and decrease loads on command. The program targets system peaks on average of five to eight times per month for an average of three to six hours at a time. Participating customers receive electronic notification of an event at least four hours in advance. At the time of the event, participating customers' storage devices are dispatched in accordance with pre-determined power discharge rates and durations.[144]

California has been actively investigating BYOD programs for years. It has aggressive state goals for decarbonization and a large and growing base of solar and solar plus storage installations. Southern California Edison recently announced a partnership with Sunrun to aggregate the residential solar plus storage systems of 300 customers into a "virtual power plant" that can be dispatched like a physical asset to reduce demand during peak hours.[145]

APS is well suited for a BYOD program. It has excellent solar resources, and increasingly, customers are installing home batteries with their solar systems. While these DERs provide resilience and backup power to customers, they have the potential to do so much more. Implementing a BYOD program to leverage unrealized capabilities of DERs such as solar plus storage systems, EV chargers, and grid-connected water heaters can help

---

[142] *See* Mass. Dept. Pub. Utils., Docket No. 20-35, Pre-filed Testimony of Ezra J. McCarthey on behalf of National Grid at pp. 13-14 (Mar. 16, 2020).

[143] https://greenmountainpower.com/product/bring-your-own-device/

[144] Green Mountain Power Corporation, *Bring Your Own Device ("BYOD") Terms & Conditions* (version: June 3, 2020) *available at* https://greenmountainpower.com/bring-your-own-device/battery-systems/ ("*GMP BYOD Terms and Conditions*").

[145] https://energized.edison.com/stories/can-your-home-battery-help-power-the-grid-in-times-of-need

APS more cost-effectively meet its load growth projections and increase demand flexibility needed to integrate more renewable energy on its bulk power grid.

BYOD Program Structure Recommendations

Q217. WHAT STRUCTURE DO YOU RECOMMEND FOR THE BYOD PROGRAM?

A217. I recommend that APS implement a technology-neutral tariff that describes the services required and the compensation mechanism for participants in the BYOD program and allows aggregators to enroll and manage DERs on behalf of individual customers. I recommend that residential and most non-residential customers participate in the tariff through a service aggregator, but sophisticated non-residential customers could choose to participate directly with the utility. Given Arizona's rich solar insolation and growing battery storage industry, the BYOD program should be designed to fully unlock the benefits of solar plus storage systems for the grid and all ratepayers.

The tariff would work in conjunction with distribution deferral opportunities identified by APS that define either system-wide or location-specific distribution needs. These opportunities can be offered on an annual basis and would be the outcome of the Company's distribution planning process. As an example, APS may identify a substation that is in need of an upgrade in two years unless 2 MW of load reduction could be realized from customers served by the substation. It would define the technical requirements of the needed solution and attach a corresponding value to the deferral that is lower than the cost of deferral of the traditional utility upgrade that would otherwise be performed. Aggregators would then work to sign up customers in the specific location, using the additional tariff revenue to enroll existing customers or to help deploy new systems.

By offering a technology-neutral tariff rather than a more limited program, APS can greatly reduce the administrative burden on itself, on aggregators, and on customers. Programs often come with substantial overhead, whether via applications or monitoring and reporting requirements. By contrast, tariffs offer a cost-effective and administratively simple framework with which customers and aggregators are already familiar. These would increase DER deployment and help integrate customer-sited solutions for both short-term and long-term distribution service needs. Further, the tariffs can be designed in a manner that will split the savings between the utility and the customer, ensuring that all parties benefit, and have terms and conditions that provide safeguards and assure performance.

Q218. WHAT TYPE OF COMPENSATION STRUCTURE DO YOU RECOMMEND FOR THE BYOD TARIFF?

A218. I recommend a two-tiered compensation structure that provides an upfront incentive for enrolling customers for a specific project and an ongoing pay-for-performance model that provides compensation for performing DERs over the duration of the tariff. The Tier 1 payment would go to the customer that is enrolling or installing their DER, while the Tier 2 payment would go to the service aggregator that is actively managing the dispatch of the DER according to the tariff terms. The specific level of the payments will depend on the value of the project that is being targeted and would persist for ten years from the initial DER signup.

This structure will create a grid service identification and incentive framework that will leverage the grid and customer benefits that DERs provide through a straightforward and efficient market participation mechanism to engage the needed resources to meet the Company's grid needs. Customer DERs can participate in one or multiple services, depending on the specific capabilities of their system, and aggregators can marshal these disparate resources in a unified direction to provide benefits.

The Tier 1 payment may be relatively modest and used primarily to animate a market for storage, helping to ensure the deployment of assets with the technical capabilities to cost-effectively ameliorate current or anticipated grid needs. The Tier 1 payment may be most appropriately furnished through a simple upfront payment or bill credit for a certain fraction of the resource's actual capacity. By only allocating a portion of the DER towards the grid need, risk to non-participants and participants is minimized; non-participants need not worry about critical resources being unavailable, while participants can continue to utilize the bulk of their DER capacity to manage their own usage. Tier 2 payments – which may be substantially higher than Tier 1 payments – can be project- or service-specific, with the payment based on the value provided. To simplify matters, the Tier 2 payment can be converted into a transparent monthly proxy capacity or other grid services credit that is administratively determined to be lower than the cost of the traditional wires-based investment or utility provided service. This ensures net benefits will flow to both participants and non-participants.

Q219. WHAT ARE SOME OTHER ADVANTAGES OF A TARIFF-BASED STRUCTURE?

A219. The tariff would be the fastest way to meet an identified need, particularly when it comes to managing issues whose resolution is needed on a short time frame. Because customers with existing DERs can enroll through the tariff, the utility may find that the existing customer base can meet the distribution service need without pursuing a time-consuming solicitation process. Further, because of the decentralized nature of DERs, it is possible to bring individual systems online in a fraction of the time that a major distribution upgrade could take. A tariff-based structure would also allow APS to proactively plan and better address future needs such as electrification and DER adoptions at reduced integration costs and broad coordination benefits across power system domains.

Q220. WOULD ENROLLING EXISTING CUSTOMERS IN THE BYOD PROGRAM AMOUNT TO DOUBLE-COMPENSATION?

A220. No. Customers are free to use their BYOD devices as they wish, such as reducing their peak demand or reducing the amount of energy purchased from the Company. The BYOD program would be leveraging assets to provide *new and additional* services, or to avoid the cost of upgrades. The cost for these new services or utility upgrades are not yet included in rates, so the customer is not avoiding them through the personal utilization of their DER. Essentially, the DERs have the potential to provide additional services that are currently untapped and uncompensated; the BYOD program identifies and monetizes these opportunities for the mutual benefit of the participant and non-participant, unlocking the full value of DERs. Instead of only providing back-up power to individuals in the case of outages, DERs would be more fully utilized for the benefit of the grid and all customers. An enrolled customer in the BYOD program would be contributing a value-add service to customers on the grid, and as such must be compensated for the value they provide.

Q221. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR THE BYOD PROGRAM.

A221. I recommend the Commission direct APS to establish a BYOD program to help meet the evolving needs of APS's grid and customer base. I recommend reviewing the BYOD programs established in other states and Sunrun's BYOD proposal to glean specific details regarding program mechanics, implementation and compensation. Program design considerations should include:

- Using a tariff-based mechanism to compensate customers with existing and new DERs and provide payments to aggregators based on value provided / performance during called events
- Structuring a two-tiered payment system that will provide some upfront incentives as well as payments to aggregators for value provided
- Setting total compensation at a level below the avoided cost of the traditional utility upgrade or service to ensure all ratepayers realize savings.

VIII. CONCLUSION

Q222. PLEASE SUMMARIZE YOUR RECOMMENDATIONS

A222. I make the following recommendations in my testimony. Collectively, these changes will recognize that solar customers provide benefits to the system and reasonably contribute to revenue adequacy. The modifications to the CCOSS method will help meet the Commission's requirements to be "transparent, accessible, and flexible." The rate design modifications will better align price signals with load conditions on the grid and provide new opportunities for residential and non-residential customers to manage their load to the benefit of all customers. The policy recommendations will remove barriers to solar deployment and can help maintain the vibrance of an industry contributing to economic development in APS's territory.

CCOSS recommendations

- Utilize more modern cost allocation approaches such as those recommended by the RAP Manual that are better suited to the operation of modern utilities.
- Provide more detail in how load shapes are calculated from billing information, including more information about demand and energy adjustments.
- Recombine solar customers with non-solar customers in the CCOSS and rate design process.
- Use delivered energy rather than site energy for solar customers.
- Remove the "solar credit" concept from the CCOSS.
- Properly adhere to the Commission's requirement that the CCOSS workpapers be transparent, accessible, and flexible as directed in Decision 75859.
- Properly adhere to the Commission's requirement that residential subclass Class NCP values are calculated based on the same hour as the combined total residential Class NCP as directed in Decision 76900.
- Develop a more robust method to account for customer growth over the test year in the CCOSS.
- Investigate ways to reduce metering costs for solar customers.

Rate Design Recommendations

- Refile R-2, R-3, and R-TOU-E tariffs with a 2 PM to 7 PM on-peak period from June to September.
- Redesign R-TECH tariff as a volumetric TOU rate.

- Remove the declining block structure for both energy and demand rates on the E-32 rates
- Remove the demand ratchet from the E-32 L tariff
- Reduce the demand charge on the E-32 S tariff to $8.805 / kW to reduce the balance of revenue recovery through demand charges to be in between the E-32 XSD and E-32 M tariffs
- Better align the "edges" between tariffs to prevent large rate shocks and disincentives for high load factor customers to reduce their demand
- Make several changes to the storage pilot guidelines that led to the E-32 L SP tariff
    - Eliminate the 20% peak demand reduction
    - Reduce the on-peak period to 4 hours
    - Create a reasonable differential between the on-peak and remaining hour demand rate
    - Increase the differential in the energy rates
    - Allow sufficient time for storage systems to be fully charged by solar

General Policy Recommendations

- Allow customers to install solar on any active residential tariff.
- Eliminate the GAC.
- Extend the demand limiter to solar customers on the R-2 and R-3 rates.
- Adopt TEP definition of connected load as the maximum demand divided by 0.6, and after multiplying this value by 125%, apply it to the AC inverter rating. Change the system size limits for residential customers to 15 kW_{AC}, 30 kW_{AC}, 45 kW_{AC}, and 60 kW_{AC} for 200-amp, 400-amp, 600-amp, and 800-amp service, respectively.
- Freeze the RCP stepdown at the 2019 Tranche level
- Extend the duration of the RCP price lock to 18 years.

BYOD Program Recommendations

- Use a tariff-based mechanism to compensate customers with existing and new DERs and provide payments to aggregators for coordinating distribution services
- Structure a two-tiered payment system that will provide some upfront deployment incentive for customers as well as payments to aggregators for value provided
- Set total compensation at a level below the avoided cost of the traditional utility upgrade or service to ensure all ratepayers realize savings.

Q223. DOES THIS CONCLUDE YOUR TESTIMONY?

A223. Yes.

Attachment KL-1, Kevin M. Lucas CV.

KEVIN M. LUCAS

SOLAR ENERGY INDUSTRIES ASSOCIATION

Mr. Lucas is Director of Rate Design for the Solar Energy Industries Association (SEIA). SEIA is the national trade association for the U.S. solar industry. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 20% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power.

Since 2010, Mr. Lucas has worked in the energy and environment industry focusing on policies such as renewable energy, energy efficiency, and greenhouse gas reduction. In his role at SEIA, Mr. Lucas develops expert witness testimony for rate cases, integrated resource plans, and other regulatory proceedings. He is actively involved in the New York Reforming the Energy Vision docket, with a focus on distributed energy resource valuation and rate design. Prior to joining SEIA, Mr. Lucas worked for the Alliance to Save Energy, a Washington DC-based nonprofit focused on reducing energy use in the built environment. Before the Alliance, he worked for the Maryland Energy Administration, the state energy office, on numerous legislative and regulatory issues and developed and presented testimony before the Maryland General Assembly and the Maryland Public Service Commission.

Prior to entering the energy and environment field, Mr. Lucas was a manager at Accenture, a leading consulting firm. Mr. Lucas implemented enterprise resource planning software for Fortune 500 companies in industries such as consumer electronics, oil and gas, and manufacturing.

AREAS OF EXPERTISE

- Renewable Energy Policy Analysis: extensive experience analyzing renewable energy policy issues and communicating results to both expert and general audiences.
- Energy Efficiency Policy Analysis: detailed understanding of energy efficiency policies, including the development of potential studies and utility efficiency program design and implementation.
- Quantitative Analysis: deep expertise in quantitative analysis across a broad range of topics including analyzing financial and operational data sets, constructing models to explore electricity industry data, and incorporating original analysis into expert witness testimony.
- Energy Markets: studies interaction of renewable energy and energy efficiency policies with wholesale market operation and price impacts.
- Legislative Analysis: reviews legislation related to energy issues to discern potential impacts on markets, utilities, and customers.

EDUCATION

Mr. Lucas holds a Masters of Business Administration from the University of North Carolina, Kenan-Flagler Business School (2009) and a Bachelor of Science in Engineering, Mechanical Engineering from Princeton University (1998).

ACADEMIC HONORS

- Beta Gamma Sigma Honor Society
- Paul Fulton Fellowship, Kenan-Flagler Business School
- Graduated *cum laude* from Princeton University

EXPERT WITNESS TESTIMONY

Public Utilities Commission of the State of Colorado

- Docket 17A-0797E – *Public Service Company - Accelerated Depreciation - AD/RR*
    - Advocating for appropriate structure to utilize renewable energy funds to support the early retirement of coal facilities and to continue to support distributed resources
- Docket 19A-0369E – *In the Matter of The Application of Public Service Company of Colorado For Approval of Its 2020-2021 Renewable Energy Compliance Plan*
    - Advocating for changes to better support solar and solar plus storage installations
- Docket 19AL-0687E - *In the Matter Of Advice No. 1814-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Reflect a Modified Schedule RE-TOU and Related Tariff Changes to be Effective on Thirty-Days' Notice*
    - Designed and advocated for new data-based default time of use rate

Maryland Public Service Commission

- Case 9153, 9154, 9155, 9156, 9157, 9362 - *In the Matter Of Maryland Utility Efficiency, Conservation And Demand Response Programs Pursuant To The Empower Maryland Energy Efficiency Act Of 2008*
    - Multiple filings regarding the design and implementation of Maryland's energy efficiency portfolio standard

- Case 9271 - *In re the Merger of Exelon Corp. & Constellation Energy Grp., Inc.*
    - Analysis of renewable energy commitments in merger proposal

- Case 9311 - *In re the Application of Potomac Elec. Power Co. for an Increase in its Retail Rates for the Distrib. of Elec. Energy*
    - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho

- Case 9326 - *In re the Application of Balt. Gas & Elec. Co. for Adjustments to its Elec. & Gas Base Rates.*
    - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho

- Case 9361 - *In re the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.*
    - Policy analysis of merger proposal

Michigan Public Service Commission

- Case U-18419 – *In the matter of the application of DTE ELECTRIC COMPANY for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.*
    - Arguing against DTE Electric's proposal to construct a new natural gas combined cycle generating facility and instead meet its future capacity and energy needs with a distributed portfolio of solar, wind, energy efficiency, and demand response.
- Case U-20162 – *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*
    - Arguing against DTE Electric's proposal for a net energy metering successor tariff that improperly undervalued the contribution of distributed solar.
- Case U-20165 - *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*
    - Discussing Consumers Energy Company's integrated resource plan, arguing for advancing the deployment of solar to meet its capacity requirements, arguing against Consumers' proposed financial compensation mechanism for third-party PPA contracts, supporting a robust PURPA market, and supporting transparent and equitable competitive procurement guidelines.
- Case U-20471 - *In the matter of the Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.*
    - Evaluating DTE's integrated resource plan, arguing for the Company to modify its modeling assumptions for solar, analyzing the operation and reliability of DTE's aging peaker fleet, demonstrating that solar and solar plus storage could replace some of DTE's peakers, advocating for robust competition and third-party access to new resources.

Public Utility Commission of Nevada

- Docket Nos. 17-06003 & 17-06004 Phase III – Rate Design – *Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.*
    - Arguing against Nevada Power Company's proposal to increase fixed customer charge

Public Utility Commission of Texas

- Docket 46831 – *Application of El Paso Electric Company to change rates*
    - Critiquing El Paso Electric's proposal to implement a three-part rate for residential and small commercial net metered customers

Attachment KL-2, SEIA 21.2.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
TWENTY-FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 8, 2020

SEIA 21.2: Please refer to the Company's response to SEIA 4.10. Confirm that only the individual sub class "delivered" loads for solar and non-solar customers are calibrated to the system peak using the demand adjustors provided in SEIA 4.10, and that the individual sub class "site" loads for solar customers are not similarly calibrated using the demand adjustors provided in SEIA 4.10

Response: Confirmed.

Witness: Leland Snook

Attachment KL-3, SEIA 4.1c

SEIA 4.1 (continued):

all formulas intact. If values from the tab "Schedule G7" refer to files external to the Development of Allocation Factors Report workbook, provide them as well in their original format with formulas intact.

j. The tab "Weighted Energy" in the Development of Allocation Factors Report contains hardcoded values for the "Annual Fuel Cost @ Generation" for each customer class. Please provide the source workpapers for these values in their original format with formulas intact.

k. For each residential rate class in the Development of Allocation Factors Report, provide the on-peak Class Peak value that occurred at the time of the "Total Residential" on-peak date and time value in the 2018-19 Load Research Report. For solar customers, provide the site, delivered, and produced values of these figures.

l. Why are customer-based costs (such as meters and OH service) allocated based on the customer count at the end of the year, instead of based on the average number of customers in the year, as is done on the Proof of Revenue workpaper?

Response:

a. Please refer to Initial Data Request 1.31 and the Excel file version of workpaper LRS_WP4DR provided on the APS 2019 Test Year Rate Case extranet site.

b. Rate classes are assigned a cost-of service class based on a number of factors such as size, usage patterns, and cost drivers. Some rates are their own cost-of-service class while others are combined with other similar rates. The R-Tech rate was combined with the other residential demand rates because it does not have enough participation at this time to determine if it warrants its own class. A mapping of rate classes to cost-of-service classes is provided in Attachment APS19RC00419.

c. Please see part b.

d. The values were based on a census of AMI meters for all Residential and most Non-Residential rates, with some customer accounts removed for incomplete data. Some Non-residential classes used a census of non-AMI interval meters.

Attachment KL-4, SEIA 4.2h.

Response to SEIA 4.2 (continued):

f. The company serves the site load for generation capacity and grid capacity costs, with an offset for the solar capacity contribution; the grid capacity cost necessary to facilitate the export solar power; the delivered energy costs, and the customer hook-up costs for the site load.

g. Please see APS's response to SEIA 2.6.b

h. The Arizona Corporation Commission has ruled that residential rooftop solar customers are different than other residential customers from a cost perspective because they are partial requirements customers that export power to the grid. Therefore, they should be treated as a separate class in a cost-of-service study. However, the Commission left the cost allocation methods to be determined in the specific utility rate cases. See Decision No. 75859 in Docket E-00000J-14-0023. The method used by the Company in this proceeding is the same method used in the sited docket and in the prior APS rate case.

Attachment KL-5, SEIA 9.4.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
NINTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 19, 2020

SEIA 9.4: Please refer to the Company's response to SEIA 4.2h. Confirm that the Commission has not explicitly approved the appropriateness of using "site" energy rather than "delivered" energy when establishing cost allocators for residential solar customers. If deny, please point to the specific Commission order approving this methodology.

Response: The Commission explicitly recognized in Decision No. 75859, in the Value and Cost of Distributed Generation proceeding, that the cost to serve solar customers is different than non-solar customers because they are partial requirements customers that export power to the grid. This means that the cost-of-service study must recognize and estimate these differences. Therefore, to base the cost study strictly on delivered load, which is the identical method for allocating costs to non-solar customers, would be incorrect, because it would not recognize these cost differences.

The Commission did not determine the precise method to be used in recognizing these cost differences – it left that up to each utility in their rate case filings. However, two fundamental approaches would be to either (1) base the initial cost allocation on site load and then credit back the cost savings attributable to the solar generation or (2) base the initial cost allocation on delivered load and then add the additional costs needed to serve solar customer. The Company has consistently used the former approach in this, and other proceedings. Please see APS's responses to SEIA 2.6, 4.2, 5.3, 5.8, 6.2, 7.12 and 9.3.

Witness: Leland Snook

Attachment KL-6, SEIA 2.6b.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 27, 2020

SEIA 2.6: Please refer to LRS_WP11DR Cost of Service Study Model.

a. Please provide all external files that are referenced in the "Import" tab in their original form with formulas intact. If the values in these files are derived from other files, please provide those files as well in their original form with formulas intact.

b. Please provide a narrative description of how the "Solar Credit" is derived and how it is used inside and outside of the Company's COSS.

c. Please provide a narrative description of what the formula in cell D103 in tab "Solar Credit" is doing.

Response:

a. The data from the referenced external files is provided in the "Import" tab below the file references. Thus, SEIA has the values for all referenced information. The file references are simply the mechanics of how that data gets imported into the model. To the extent that SEIA is seeking additional source data and/or all files from which these values were derived, APS objects to this data request as cumulative and unduly burdensome.

b. In the COSS, APS uses the data for the residential solar customer's entire load at the home — load served both by APS and the customer's rooftop solar system — as the starting point for cost allocation to develop the Coincident Peak (CP), Non-Coincident Peak (NCP) and Sum of Individual Max demand allocations, as well as the energy allocations.

APS then credits the customer for:

- All their self-provided production capacity based on a comparison to the APS-delivered customer load using both the four summer sub-class CPs and NCPs;
- Their entire energy production, including both what the customer consumes on site and what is delivered from the solar customer to the grid;
- The avoided transmission cost based on a comparison to the APS-delivered customer load at the time of the four summer CPs;
- The avoided primary distribution cost based on a comparison to the APS-delivered customer load at the time of the four summer sub-class NCPs; and,
- The avoided secondary distribution cost based on a

Response to SEIA 2.6 (continued):

comparison to the APS-delivered customer load at the time of the four summer sub-class Sums of Individual Max.

This approach fully credits residential solar customers for all cost savings resulting from the capacity (production, transmission and distribution) and energy supplied to the grid by their rooftop solar systems. The result is that the COSS analysis only allocates capacity and energy costs to solar customers based on what APS has to provide. This analytical approach also captures the cost of providing grid services for the rooftop solar customer's export of energy and backup of the customer's self-supplied generation, including support for the starting of motors (e.g. the in-rush current associated with the starting of an air conditioning unit, which generally cannot be met by a solar array).

The solar credit is used in the cost of service model to derive the total allocated costs for the residential solar rate classes and in reporting the percent of cost of service achieved with current and proposed rates.

c. Cell D103 is computing the amount of revenue credit that is allocated to the residential solar legacy energy rate class for Production Demand.

Attachment KL-7, SEIA 7.12h.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
SEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 12, 2020

SEIA 7.12: Please refer to the Company's response to SEIA 2.6b.

a) Would the COSS produce the same mathematical result for total costs allocated under the Company's methodology (allocation based on Site load and then crediting for the difference between the Site and Delivered) and if the Company had allocated costs based on the Delivered load alone? If it would not, please explain why it would not and what cost categories would be different between the two methodologies.

b) Is it the Company's position that in crediting solar customers for the difference between their Site load and Delivered load that it is crediting back the costs that would be avoided by exported solar energy? If not, please explain in concept what the credit is for.

c) Would allocating costs based only on the Delivered component of the solar customer's use also "allocate[] capacity and energy costs to solar customers based on what APS has to provide"? If not, please explain why. If so, why does the Company not allocate costs this way?

d) Explain in detail how the Company's analytical approach also captures the cost of providing grid services for the rooftop solar customer's export of energy and backup of the customer's self-supplied generation, including support for the starting of motors (e.g. the in-rush current associated with the starting of an air conditioning unit, which generally cannot be met by a solar array).

e) Please indicate where in the COSS customers are allocated costs specific to the "in-rush current" grid service.

f) What allocators are used for costs associated with the "in-rush current" grid service costs?

g) How does the Company track when it has provided the "in-rush current" grid service to solar and non-solar customers?

h) Please indicate where in the COSS customers are allocated costs specifically for maintaining distribution voltage within the required operating limits.

i) What grid services and/or assets are required to handle the

Witness: Leland Snook

SEIA 7.12 (continued): export of solar energy from residential customers to the grid that are also not required to handle the delivery of energy from the grid to residential customers?

Response:

a) No. Please see the Company's response to SEIA 6.2.c.

b) No. It is a credit for the entire solar generation – both the export power and the self-consumed power.

c) No. Please see APS's response to SEIA 7.12.d.

d) No. The extra costs for grid services and back-up services are captured by using site load for the initial starting cost allocation. If the allocation started with delivered load these extra costs would have to be added back in to the final cost allocation. The extra grid cost created by rooftop solar for the export power, in terms of two-way power flow, distribution feeder capacity and planning, and any other related issues are not captured by the current site load/credit approach.

e) This is not a specific allocated amount. However, the costs would generally be included in the demand-related components for the generating plants and the grid.

f) Please see part e.

g) Please see the Company's response to SEIA 7.12.e.

h) This is not a specific category, but rather included in distribution primary and substation costs.

i) APS has a commitment to maintain system voltage at the Point of Delivery (POD) in accordance with ANSI C84.1 as noted in the Arizona Administrative Code R14-2-208F. Solar customers in areas with high solar adoption have the potential to cause high voltage during the Spring and Fall months. APS has an obligation to maintain voltage, and installing or upgrading traditional equipment such as reconductoring, feeder additions, transformer upgrades, capacitor banks and voltage regulators are some options available to APS. These standard equipment types are installed to maintain system reliability for residential and C&I customers as well, however the application and need for such upgrades and additions may be different on feeders

Attachment KL-8, SEIA 7.12e.

SEIA 7.12: Please refer to the Company's response to SEIA 2.6b.

a) Would the COSS produce the same mathematical result for total costs allocated under the Company's methodology (allocation based on Site load and then crediting for the difference between the Site and Delivered) and if the Company had allocated costs based on the Delivered load alone? If it would not, please explain why it would not and what cost categories would be different between the two methodologies.

b) Is it the Company's position that in crediting solar customers for the difference between their Site load and Delivered load that it is crediting back the costs that would be avoided by exported solar energy? If not, please explain in concept what the credit is for.

c) Would allocating costs based only on the Delivered component of the solar customer's use also "allocate[] capacity and energy costs to solar customers based on what APS has to provide"? If not, please explain why. If so, why does the Company not allocate costs this way?

d) Explain in detail how the Company's analytical approach also captures the cost of providing grid services for the rooftop solar customer's export of energy and backup of the customer's self-supplied generation, including support for the starting of motors (e.g. the in-rush current associated with the starting of an air conditioning unit, which generally cannot be met by a solar array).

e) Please indicate where in the COSS customers are allocated costs specific to the "in-rush current" grid service.

f) What allocators are used for costs associated with the "in-rush current" grid service costs?

g) How does the Company track when it has provided the "in-rush current" grid service to solar and non-solar customers?

h) Please indicate where in the COSS customers are allocated costs specifically for maintaining distribution voltage within the required operating limits.

i) What grid services and/or assets are required to handle the

SEIA 7.12 (continued): export of solar energy from residential customers to the grid that are also not required to handle the delivery of energy from the grid to residential customers?

Response:

a) No. Please see the Company's response to SEIA 6.2.c.

b) No. It is a credit for the entire solar generation – both the export power and the self-consumed power.

c) No. Please see APS's response to SEIA 7.12.d.

d) No. The extra costs for grid services and back-up services are captured by using site load for the initial starting cost allocation. If the allocation started with delivered load these extra costs would have to be added back in to the final cost allocation. The extra grid cost created by rooftop solar for the export power, in terms of two-way power flow, distribution feeder capacity and planning, and any other related issues are not captured by the current site load/credit approach.

e) This is not a specific allocated amount. However, the costs would generally be included in the demand-related components for the generating plants and the grid.

f) Please see part e.

g) Please see the Company's response to SEIA 7.12.e.

h) This is not a specific category, but rather included in distribution primary and substation costs.

i) APS has a commitment to maintain system voltage at the Point of Delivery (POD) in accordance with ANSI C84.1 as noted in the Arizona Administrative Code R14-2-208F. Solar customers in areas with high solar adoption have the potential to cause high voltage during the Spring and Fall months. APS has an obligation to maintain voltage, and installing or upgrading traditional equipment such as reconductoring, feeder additions, transformer upgrades, capacitor banks and voltage regulators are some options available to APS. These standard equipment types are installed to maintain system reliability for residential and C&I customers as well, however the application and need for such upgrades and additions may be different on feeders

Attachment KL-9, SEIA 11.9.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
ELEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 27, 2020

SEIA 11.9: Please refer to the Company's response to SEIA 7.12(i). Please provide the count and cost of the following that have been installed or upgraded on the Company's system that were specifically required as the result of customers installing solar.

a) Reconductoring
b) Feeder additions
c) Feeder upgrades
d) Transformer additions
e) Transformer upgrades
f) Capacity bank additions
g) Capacity bank upgrades
h) Voltage regulator additions
i) Voltage regulator upgrades

Response: APS manages infrastructure investments to ensure that all facilities remain within acceptable thermal ratings, and that voltage remains within acceptable tolerances as defined by ANSI C84.1 as previously indicated. This is true for managing grid constraints considering existing and forecasted near-term additions of both load and generation to the existing grid infrastructure.

APS does not track costs in a way that allows it to determine whether or not specific upgrades and additions were caused by installing solar. Therefore, costs are not provided for sub-parts a through f. APS is aware of system voltage correction and management costs, of which customer solar installations are a contributing factor. These costs are provided in sub-part g.

a) The physics of the system (conductor type, length, physical properties, rated ampacity, reliability profile) determines the need for circuit reconductor based on expected current magnitudes on the circuit. APS has either extended a circuit to connect a generation facility (and loads) or upgraded to a larger wire size to accommodate solar PV (and load) interconnections based on customer request.

b) In the rate-case test year, APS has not added dedicated feeder circuits to connect PV. Feeder extensions (referenced in 11.9(a) are also additions to feeder infrastructure.

c) See 11.9(a) and (b).

d) The physics of the system determines the need for transformer additions or upgrades for both solar and load

Witness: TBD

Response SEIA 11.9 (continued):

additions. APS has added transformers to connect PV sites. Note that PV installations can be behind-the-meter (e.g. rooftop PV behind an existing load interconnection) or standalone (e.g. solar covered parking, large facilities). Known transformer additions have been to accommodate larger standalone PV sites.

e) See 11.9(d)

f) See 11.9(g), (h), and (i)

g) Capacitor bank upgrades and voltage regulation infrastructure is a key focus in a high-PV-penetration system. The physics of the distribution grid, with variable resources like PV, results in wider voltage swings (PV induced light loads and ultimately reverse power flows), rapid voltage variability (corresponding to PV intermittency), and an inability to respond to grid disturbances (as evidenced in Germany's 50.2 Hz problem, and in the CA Blue Cut Fire event where 1200 MW* of solar PV was known to trip offline erroneously triggering national NERC Alerts). Many of the voltage, frequency, and grid impacts are well documented by the National Renewable Electric Labs (NREL), Electric Power Research Institute (EPRI), Institute of Electrical and Electronics Engineers (IEEE), and other states with large distributed renewable portfolios, including California and Hawaii. A component of APS's grid modernization investments include deployment of bi-directional capacitor bank controllers, feeder voltage regulators, and the control intelligence to provide for flexible operation with large volumes of solar PV, frequent instances of reverse power flow, higher voltage intermittency, and growing volumes of these types of interconnections. The IEEE 1547-2018 standard recognizes these challenges with voltage, frequency and disturbance response and provides guidance to the technology/inverter vendors to develop products that provide suitable voltage performance while still maintaining predictable synchronism to the grid during disturbance conditions.

ExcelAPS19RC00900 contains information related to capacitor banks required as the result of increased voltage fluctuations and voltage variability, to which customer solar PV installations are a contributing factor.

Witness: TBD

Response SEIA 11.9 (continued):	h) See 11.9 (g) i) See 11.9 (g)

Attachment KL-10, SEIA 22.1.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S TWENTY SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 9, 2020

SEIA 22.1: Please refer to the Company's response to SEIA 11.9.

a) In 11.9a, was the customer(s) that APS extended a circuit to connect a generation facility a residential customer or a non-residential customer?

b) In 11.9a, was the customer(s) that APS upgraded to a larger wire size to accommodate solar a residential customer or a non-residential customer?

c) In 11.9a, who was responsible for the cost of the upgrades?

d) In 11.9d, was the new transformer added to connect PV sites done for residential or non-residential customers? Please indicate how many new transformers were added, and how many of those were for residential and non-residential customers. Who was responsible for the cost of the new transformer?

e) In 11.9g, how much of the SPR CAPBNK FY20 budget was due to the installation and deployment of Aprisa Radios for a future 900 MHz infrastructure? How many of the 17 feeders served predominantly residential customers? Non-residential customers?

Response: a. The vast majority of APS customer solar interconnections over the rate case test year were residential rooftop solar (14,949), which are generally connected behind the customers' meter. These already existing customers generally do not require line extensions.

Larger scale generation interconnecting customers may connect behind the existing meter (no additional infrastructure is generally required if the system is sized appropriately) or stand-alone site (may require line extension). There were 159 non-residential interconnections during this time-period.

The AZ Solar Communities installation at St. Vincent De Paul is an example of a site that required a line extension to include all 3 phases and add a transformer to support the installation. The solar site covers the parking lot of the facility but is connected to a different feeder than the building load.

Witness: TBD

Response to SEIA 22.1 (continued):

b. The example in part a is a non-residential customer.

c. During the interconnection/review process, APS and the customer or developer may discuss options to reduce or eliminate infrastructure needs. For example, appropriate siting, points of interconnection, and intended operation all factor into those decisions. Again, the physics of the system determine the need for wires, transformers or other equipment.

In the example (St. Vincent de Paul), APS paid the cost of the line extension and system upgrades as the system was part of the AZ Solar Communities program, in which all necessary infrastructure is provided by the Company.

Additional information about the cost responsibility for interconnecting distributed energy resources can be found at aps.com/dg. Key documents include the Electric Service Requirements Manual (ESRM) and the DG Interconnection Requirements Manual (DG IRM). An excerpt from section 5 of the interconnection requirements manual in effect during the Test Year states the following:

> 5.1 Facilities and Costs: The Customer is responsible for all facilities required to be installed solely to interconnect the Customer's generation facility to the APS System. This includes connection, transformation, switching, protective relaying, metering and safety equipment, including a visibly-open Disconnect Switch and any other requirements as outlined in this document, the ESRM and applicable rate schedules as well as any other special items specified by APS. All such Customer facilities are to be installed by the Customer at the Customer's sole expense. In the event that additional facilities are required to be installed on the APS System to accommodate the Customer's generation, APS will install such facilities at the Customer's expense. APS may also charge the Customer for any administrative costs and/or the costs of studies required to interconnect the Customer's generation.

d. The example previously described was a non-residential installation. As generally stated, a behind-the-meter PV system on an existing customer's rooftop will not require an additional transformer.

Witness: TBD

Response to SEIA 22.1 (continued):	No additional transformer additions were identified as the result of PV installation. Typical cost responsibility is discussed in part c above for a customer connecting distributed energy resources. e. APS is still compiling the data for this response and will provide as soon as it is available.

Attachment KL-11, SEIA 4.2f.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 4, 2020

SEIA 4.2: Please refer to workpaper LRS_WP4DR (Development of Allocation Factors Report) and Initial 1.31_APS19RC00282 (2018-19 Load Research Report).

a. Confirm that "site" represents the gross load of a customer (i.e. load met by both solar generation and grid power) while "delivered" represents the net load of a customer (i.e. load met by grid power). If deny, please explain the difference between these values.

b. Confirm that the Development of Allocation Factors Report uses the "site" values rather than the "delivered" values from the 2018-19 Load Research Report for residential solar rate classes. If deny, please reconcile the values between these two workpapers.

c. Please explain how the "site", "delivered", and "produced" values for an individual customer in an individual hour are determined. Include a discussion and mathematical examples of what meters are used, how instantaneous power flows are integrated, and how integrated power flows are combined to produce these values. Also include a discussion on how these values are calculated when a single hour has some duration where the household is exporting energy and some duration when the household is importing energy.

d. Confirm that the Development of Allocation Factors Report uses "delivered" values (as defined above) from the 2018-19 Load Research Report for nonresidential customers that have solar. If deny, please reconcile the values between these two workpapers and provide load studies and allocation factor workpapers that break out non-commercial solar customers.

e. Why does the Company differentiate between "site" and "delivered" load when allocating costs for residential solar customers but not when allocating costs for non-residential customers?

f. Does the Company serve the "delivered" energy and demand of a solar customer, or does it serve the "site" energy and demand of a solar customer?

g. What is the basis for using "site" energy and demand when establishing cost allocators for residential solar customers?

Witness: Leland Snook

SEIA 4.2 (continued):

h. Has the Commission explicitly ruled on the appropriateness of using "site" or "delivered" energy when establishing cost allocators for residential solar customers? If so, please provide the Commission order and page reference.

Response:

a. Yes. Correct.

b. Yes. Correct.

c. A solar customer has a bi-directional meter that measures delivered and received energy, where delivered energy is energy APS delivers to the customer and received energy is exported from the customer to the APS grid. Additionally, a solar customer has a production meter that measures the solar generation. Through the course of an hour, the bi-directional meter integrates near instantaneous measurements of delivered and received energy to create hourly intervals for both of these values. The production meter measures "produced" energy in a similar manner. Site load is then calculated afterwards by the equation

   Site = Delivered + Produced – Received

   where each value represents an integrated hour. During an hour where there is both received and delivered energy, the intervals for delivered, received, and produced energy are calculated independently and all three would have separate positive values. After which, Site is then calculated by the equation above.

d. Yes. The non-residential solar customers were not broken out in to a separate cost-of-service class. Therefore, they were allocated costs based on delivered load, similar to the non-solar customers in their class.

e. The Company did not propose a separate cost-of-service class for non-residential solar customers in this proceeding. This is because the non-residential rates typically recover a high percentage of grid costs through demand charges rather than energy charges, which is more aligned with the cost to serve these customers. In addition, the adoption of behind the meter solar for the general service class is significantly lower than for the residential class.

Witness: Leland Snook

Response to SEIA 4.2 (continued):

f. The company serves the site load for generation capacity and grid capacity costs, with an offset for the solar capacity contribution; the grid capacity cost necessary to facilitate the export solar power; the delivered energy costs, and the customer hook-up costs for the site load.

g. Please see APS's response to SEIA 2.6.b

h. The Arizona Corporation Commission has ruled that residential rooftop solar customers are different than other residential customers from a cost perspective because they are partial requirements customers that export power to the grid. Therefore, they should be treated as a separate class in a cost-of-service study. However, the Commission left the cost allocation methods to be determined in the specific utility rate cases. See Decision No. 75859 in Docket E-00000J-14-0023. The method used by the Company in this proceeding is the same method used in the sited docket and in the prior APS rate case.

Attachment KL-12, SEIA 9.3a.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
NINTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 19, 2020

SEIA 9.3: Please refer to the Company's response to SEIA 4.2f, which states "The company serves the site load for generation capacity and grid capacity costs, with an offset for the solar capacity contribution." Suppose a customer has a peak site demand of 10 kW, and during that same time, she has a solar array that is producing 4 kW of power, which results in a delivered peak demand of 6 kW.

a) Confirm that the "offset for the solar capacity contribution" is a construct that exists in the Company's COSS and does not apply to the physical operation of the grid. If deny, please explain from an electrical power flow perspective how the Company is serving 10 kW of site demand from its power grid while actively offsetting 4 kW of solar capacity contribution.

b) Confirm that in the example above, the Company is providing 6 kW to the customer's meter from the power grid.

c) Does the Company analyze each new residential hookup individually when considering what size service drop or transfer to install, and then install that specific capacity, or does the Company have standard-sized service drops (e.g. 200 amp or 400 amp service) that it uses unless an exception is warranted?

Response: a. Deny. The Company would be supplying more than just the 6 kW used by the customer at that instant. The fuel cost necessary to generate the energy to serve the customer would be based on 6 kW. However, the generator capacity, transmission capacity, distribution primary and distribution secondary capacity necessary to serve the customer would be based on a much higher level of demand than the 6 kW of net load used in this example. Please see APS's responses to SEIA 4.2, 5.3 and 7.12. Also note, the Company's Cost of Service Study allocates costs on a class basis, so the particular class would be allocated costs on the appropriate allocation factor. The specific circumstances of an individual residential solar customer would be subsumed by the subclass. The precise implications for this hypothetical example are dependent on a number of other factors, such as whether the hour referenced is aligned with the subclass coincident peak, non-coincident peak and how it affects the sum of individual max peak.

b. Deny. Please see APS's response to part a.

c. Please see APS's response to SEIA 5.3. The Company has a standard range of equipment sizes.

Witness: Leland Snook

Attachment KL-13, SEIA 16.2a.

SOLAR ENERGY INDUSTRY ASSOCIATION'S
SIXTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 29, 2020

SEIA 16.2: Please refer to Rate Rider EPR-6.

a) What is the maximum power than can be provided by the Company to a residential customer through a 200-amp service? Through a 400-amp service? Through a 600-amp service? Through an 800-amp service?

b) What is the engineering / technical purpose of limiting the nameplate capacity of residential DG systems based on the amperage of the service as found in Generator Requirement 3?

c) What piece of equipment (e.g. line transformer, meter, etc.) is the bottleneck that determines the nameplate capacity limits of the residential DG system as found in Generator Requirement 3?

d) What is the engineering / technical purpose of limiting the nameplate capacity of a DG system over 10 kW to 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve months as found in Generator Requirement 4?

e) What piece of equipment (e.g. line transformer, meter, etc.) is the bottleneck that determines the nameplate capacity limits of the DG system over 10 kW as found in Generator Requirement 4?

f) If a residential customer has installed and is paying for 800-amp service that is able to serve a maximum DG system of 60 kW-dc, and has a peak demand of 20 kW-ac, what basis does the Company have for restricting the size of a DG system to 30 kW-ac? Please explain from both a policy, cost, and engineering perspective.

g) Is the Company aware of other utilities that place similar DG size restrictions on DG systems over 10 kW based on the peak demand of the customer? If so, please provide a list of such utilities.

h) Is the Company aware that other utilities often place DG size restrictions based on the total amount of annual energy that a DG system produces compared to the customer's annual load (such as 100% or 125% of customer annual energy usage)?

Witness: Jessica Hobbick

SEIA 16.2 (continued):

i) Would the Company consider shifting the size requirement to be one based on customer annual energy usage rather than customer maximum one-hour peak demand? If not, please explain why not.

Response:

a) For a typical residential interconnection, the theoretical maximum for a 200-Amp panel serving 120/240 Volt service is 38.4 kW factoring in NEC recommended maximum breaker loading, customer panel configurations and delivery voltages. The maximum load for 400-Amp, 600-Amp, and 800-Amp service are proportional to the panel amperage. In reality, customers use a mix of 120- and 240- Volt circuits for their appliances, so the maximum kW demand from the panel will vary and be lower than 240-volt number.

However, the distribution service equipment is not sized to serve the maximum potential draw from each customer based on their service amperage. Nor is it sized to accommodate solar generators that could potentially export 150% of each customer's maximum load back to the grid. Please refer to the Company's responses to SEIA 5.1, SEIA 5.2, and SEIA 5.3.

A more typical residential installation for 200-amp service would be sized to serve roughly 12.23 kW, which is derived as shown below. The other typical power supplies are: 400-Amp - 24.46 kW, 600-Amp - 36.69 kW, and 800-Amp - 48.92 kW.

Typical power delivery for 200-Amp service

(200 A) x (0.8) x (0.35) x (240 V) x (0.91) = 12.23 kW

Where:

Panel amperage rating (SES): 200 A
NEC safety factor: 0.8
Typical residential demand factor: 0.35
Operating voltage: 240 V
Typical residential load power factor: 0.91

b) Given the significant subsidies for the net metering program, certain size limitations were established in the net metering

Attachment KL-14, SEIA 22.2.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
TWENTY SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 9, 2020

SEIA 22.2: When developing its generation planning reserve margin, does the Company assume in its load forecast the site load for solar customers or the delivered load for solar customers?

Response: Site load is used for customers projected to adopt solar and delivered load is used for existing solar customers. APS reviews and evaluates its approach to reserve margins through the IRP process and will continue to keep stakeholders informed of any updates.

Witness: Brad Albert

Attachment KL-15, SEIA 4.3.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 4, 2020

SEIA 4.3: Please refer to LRS_WP11DR Cost of Service Study Model. Please provide the source documents for the value of the "Solar Energy Credit" found in cells H6750:H6753 in tab "Import". Please also provide a narrative description of how this value was calculated and what it represents.

Response: The solar energy credit represents the energy value of solar production, which is credited against the allocated cost-of-service for the site load. It is based on hourly solar production and the relevant avoided energy cost. See Attachment ExcelAPS19RC00531. Also, please refer to SEIA 2.6.b.

Witness: Leland Snook

Attachment KL-16, SEIA 4.8c.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 4, 2020

SEIA 4.8: Please refer to LRS_WP11DR (Cost of Service Study), LRS_WP4DR (Development of Allocation Factors Report) and Initial 1.31_APS19RC00282 (2018-19 Load Research Report). On the "Control" tab of the Cost of Service Study, the values for the "Demands – Solar Credits" appear to be derived from the 2018-19 Load Research Report. However, there appears to be inconsistencies between the various workpapers in terms of which values are derived from which customer class.

a. The values from the "Legacy Solar (Demand)" customer class in the Allocation Factors Report correspond to the "ECT Solar Site" customer class from the Load Research workpaper, but the values for the "Legacy Solar (Demand)" customer class in the COSS "Control" tab correspond to the "Demand Rate Solar" customer class from the Load Research workpaper.Please explain this inconsistency.

b. The values from the "R-Solar (TOU)" customer class in the Allocation Factors Report correspond to the "R-TOU-E Solar Site" customer class from the Load Research workpaper, but the values for the "R-Solar (TOU)" customer class in the COSS "Control" tab correspond to the "Energy Rate Solar" customer class from the Load Research workpaper. Please explain this inconsistency.

c. The "Demands – Solar Credit" values from the COSS for the Delivered NCP, Site NCP, Delivered Ind Max, and Site Ind Max are all summer average values. However, the cost allocation factors for these are based on the single NCP and Ind Max value. Why did the Company use the summer average rather than the single value in the COSS calculation?

d. Some of the load study demands from customer classes that are used in the allocation workpapers are based on demand levels obtained during off-peak hours. Given that residential rate designs that have a demand charge are only based on the on-peak demand, why are costs allocated in part based on off-peak demands?

Response: a. The Company has noted this discrepancy and will provide a revised analysis in a supplemental response to this request.

b. The Company has noted this discrepancy and will provide a revised analysis in a supplemental response to this request

Witness: Leland Snook

Response to SEIA 4.8 (continued):

c. The solar credit is based on the average summer values because they are more representative of the solar contribution to NCP and Ind Max. For example, the solar performance during one particular NCP hour in the summer could vary considerably depending on weather conditions or other factors. This same risk would not be very likely for the entire load of the home without solar. This is the same method APS used in the COS/VOS proceeding (Decision No. 75859) and in its last rate case.

d. For residential time-of-use rates weekends are considered off-peak even though the weekend loads in the core summer months can be very high, as evidenced by the fact that the rate class non-coincident peak can fall on a weekend during these months. The demand charge only applies to the on-peak hours, which are weekdays, 3-8 pm, excluding holidays, for customer considerations. Delivering costs are driven by non-coincident peak regardless of when it may occur.

Witness: Leland Snook

Attachment KL-17, SEIA 9.8.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
NINTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 19, 2020

SEIA 9.8: Please refer to the Company's response to SEIA 4.8c. Given the Company's concern of the riskiness that solar performance during one particular NCP and Ind Max hour in the summer could vary considerably depending on weather conditions or other factors, why is it willing to expose solar customers to the risk of a single hour's performance in the allocation of costs by using one particular NCP and Ind Max hour and not the summer average values that are more representative to the solar contribution to NCP and Ind Max?

Response: The costs associated with the site load were allocated on the same basis as all other residential rate classes and appropriately reflect the drivers for those costs.

Witness: Leland Snook

Attachment KL-18, SEIA 2.6a.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 JANUARY 27, 2020

SEIA 2.6: Please refer to LRS_WP11DR Cost of Service Study Model.

a. Please provide all external files that are referenced in the "Import" tab in their original form with formulas intact. If the values in these files are derived from other files, please provide those files as well in their original form with formulas intact.

b. Please provide a narrative description of how the "Solar Credit" is derived and how it is used inside and outside of the Company's COSS.

c. Please provide a narrative description of what the formula in cell D103 in tab "Solar Credit" is doing.

Response:

a. The data from the referenced external files is provided in the "Import" tab below the file references. Thus, SEIA has the values for all referenced information. The file references are simply the mechanics of how that data gets imported into the model. To the extent that SEIA is seeking additional source data and/or all files from which these values were derived, APS objects to this data request as cumulative and unduly burdensome.

b. In the COSS, APS uses the data for the residential solar customer's entire load at the home — load served both by APS and the customer's rooftop solar system — as the starting point for cost allocation to develop the Coincident Peak (CP), Non-Coincident Peak (NCP) and Sum of Individual Max demand allocations, as well as the energy allocations.

APS then credits the customer for:

- All their self-provided production capacity based on a comparison to the APS-delivered customer load using both the four summer sub-class CPs and NCPs;
- Their entire energy production, including both what the customer consumes on site and what is delivered from the solar customer to the grid;
- The avoided transmission cost based on a comparison to the APS-delivered customer load at the time of the four summer CPs;
- The avoided primary distribution cost based on a comparison to the APS-delivered customer load at the time of the four summer sub-class NCPs; and,
- The avoided secondary distribution cost based on a

Response to SEIA 2.6 (continued):

comparison to the APS-delivered customer load at the time of the four summer sub-class Sums of Individual Max.

This approach fully credits residential solar customers for all cost savings resulting from the capacity (production, transmission and distribution) and energy supplied to the grid by their rooftop solar systems. The result is that the COSS analysis only allocates capacity and energy costs to solar customers based on what APS has to provide. This analytical approach also captures the cost of providing grid services for the rooftop solar customer's export of energy and backup of the customer's self-supplied generation, including support for the starting of motors (e.g. the in-rush current associated with the starting of an air conditioning unit, which generally cannot be met by a solar array).

The solar credit is used in the cost of service model to derive the total allocated costs for the residential solar rate classes and in reporting the percent of cost of service achieved with current and proposed rates.

c. Cell D103 is computing the amount of revenue credit that is allocated to the residential solar legacy energy rate class for Production Demand.

Attachment KL-19, SEIA 4.8a.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 4, 2020

SEIA 4.8: Please refer to LRS_WP11DR (Cost of Service Study), LRS_WP4DR (Development of Allocation Factors Report) and Initial 1.31_APS19RC00282 (2018-19 Load Research Report). On the "Control" tab of the Cost of Service Study, the values for the "Demands – Solar Credits" appear to be derived from the 2018-19 Load Research Report. However, there appears to be inconsistencies between the various workpapers in terms of which values are derived from which customer class.

a. The values from the "Legacy Solar (Demand)" customer class in the Allocation Factors Report correspond to the "ECT Solar Site" customer class from the Load Research workpaper, but the values for the "Legacy Solar (Demand)" customer class in the COSS "Control" tab correspond to the "Demand Rate Solar" customer class from the Load Research workpaper.Please explain this inconsistency.

b. The values from the "R-Solar (TOU)" customer class in the Allocation Factors Report correspond to the "R-TOU-E Solar Site" customer class from the Load Research workpaper, but the values for the "R-Solar (TOU)" customer class in the COSS "Control" tab correspond to the "Energy Rate Solar" customer class from the Load Research workpaper. Please explain this inconsistency.

c. The "Demands – Solar Credit" values from the COSS for the Delivered NCP, Site NCP, Delivered Ind Max, and Site Ind Max are all summer average values. However, the cost allocation factors for these are based on the single NCP and Ind Max value. Why did the Company use the summer average rather than the single value in the COSS calculation?

d. Some of the load study demands from customer classes that are used in the allocation workpapers are based on demand levels obtained during off-peak hours. Given that residential rate designs that have a demand charge are only based on the on-peak demand, why are costs allocated in part based on off-peak demands?

Response:

a. The Company has noted this discrepancy and will provide a revised analysis in a supplemental response to this request.

b. The Company has noted this discrepancy and will provide a revised analysis in a supplemental response to this request

Witness: Leland Snook

Attachment KL-20, SEIA 11.5.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
ELEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 27, 2020

SEIA 11.5: Please refer to the Company's response to SEIA 7.1 and SEIA 2.7. In SEIA 2.7(d), the Company indicated that the installation labor for a bi-directional, standard, and production were $92.65, $26.08, and $26.08, respectively. In SEIA 7.1(l), the Company stated "Installation of a bi-directional meter is the same as a standard meter, except that typically APS would also set the additional production meter during the same visit." In SEIA 7.1(m), the Company stated that "Installation costs are determined by the job classification and the time it takes to perform the work."

a) Confirm that the total cost of a production meter contains labor costs to install that meter, and these costs are to install only that production meter. If deny, please explain.

b) Confirm that the total cost of a standard meter contains labor costs to install that meter, and these costs are to install only that standard meter. If deny, please explain.

c) Confirm that the total cost of a bi-directional meter contains labor costs to install that meter, and these costs are to install only that bi-directional meter. If deny, please explain.

d) Confirm that the same worker installs the production meter and the bidirectional meter on the same visit. If deny, please explain.

e) Please explain why the Company charges more than 3.5 times as much to install a bi-direction meter as a standard or production meter if the same person takes the same amount of time to install either of the meters.

Response:

a) Confirmed.

b) Confirmed.

c) Confirmed.

d) If the solar installation passes inspection, APS will set both the bi-directional billing meter and the production meter on the same visit.

e) The cost of meter installation provided in SEIA 2.7(d) inadvertently reflected an error. The cost to install the bi-directional billing meter and the production meter is the same at $26.08 per meter installed. Please see the table below for

Response to SEIA 11.5 (continued): revised meter and meter installation costs.

Typical Cost of Residential Meters

	Meter Cost	Shop Cost	Installation Material	Installation Labor	Total Cost
Standard	106.24	1.65	3.09	26.08	137.06
Bi-directional	310.00	13.40	3.59	26.08	353.07
Production	68.94	1.65	3.09	26.08	99.76
Total Solar					$452.83

Witness: Leland Snook

Attachment KL-21, SEIA 10.3.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 20, 2020

SEIA 10.3: Please refer to the Company's responses to SEIA 4.4 and 4.10.

a) Please provide a corrected monthly customer count for each cost of service class included in Attachment SEIA 4.10 consistent with the Company's Load Study report.

b) Please indicate if these figures represent the count of customers on the first day of the month, the last day of the month, or the average during the month.

c) If the customer count represents the customers on the last day of the month, please provide the customer counts as of July 1, 2018 for each cost of service class in SEIA 4.10.

d) If the customer count represents the customers on the first day of the month, please provide the customer counts as of June 30, 2019 for each cost of service class in SEIA 4.10.

e) If the figures represent the average customers in a month, please provide customer counts for both July 1, 2018 and June 30, 2019 for each cost of service class in SEIA 4.10.

Response:

a. Please see attachment APS19RC00694 for the corrected customer count. See Initial Data Request 1.31 for all other customer counts.

b. The monthly customer count is, with a few exceptions, the sum of bills issued across all billing cycles in the month and therefore most closely reflects an average across the month. To be counted as a customer, a bill must be for an active customer or a newly connecting customer with 16 days or more in their current billing cycle. Newly connecting customers with fewer than 16 days and disconnecting customers (final bills) are not counted as customers.

c. Not applicable. The customer counts do not represent the customers on the last day of the month.

d. Not applicable. The customer counts do not represent the customers on the first day of the month.

e. The customer count does not represent the average number of customers during the month. Please see the Company's response to SEIA 10.3.b.

Witness: Leland Snook

Attachment KL-22, SEIA 4.10.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 4, 2020

SEIA 4.10: Provide 8760 hourly loads for the test year for each residential customer class in the "Initial 1.31_APS19RC00282 (2018-19 Load Research Report)" report. This request should include separate values for Delivered, Site, and Produced values for customer classes that have these load studies. Further, this request should include all data required to transform the raw 8760 data to exactly reproduce the data in each customer class's corresponding load research report.

Response: Please see attachment ExcelAPS19RC00421 for the unadjusted 8760 hourly loads for each residential customer class as outlined in APS's 2018-2019 Load Research Report. This amount is utilized in the Load Research Report where additional adjustments are made. The individual sub class loads are calibrated to the system peak using the values provided below.

Jan	-0.06083
Feb	-0.05490
Mar	-0.05745
Apr	-0.07055
May	-0.07722
Jun	-0.06453
Jul	-0.06557
Aug	-0.05717
Sep	-0.06401
Oct	-0.07826
Nov	-0.04278
Dec	-0.01449

Witness: Leland Snook

Attachment KL-23, SEIA 7.1

SOLAR ENERGY INDUSTRIES ASSOCIATION'S SEVENTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 FEBRUARY 12, 2020

SEIA 7.1: Please refer to the Company's response to SEIA 2.7.

a) How is data from the generator production meter used when billing solar customers?

b) Is it possible for the Company to bill solar customers without having a generator production meter in place?

c) Is the data from the generation production meter used for purposes other than billing customers? If so, please describe each instance of its use in detail.

d) Are the Company's standard residential AMI meters capable of being configured for bi-directional use? If so, why does the Company purchase separate meters for this purpose?

e) Are residential non-solar customers who switch to a more complex rate (such as a TOU or demand rate) charged more or allocated more costs in the COSS for metering costs than residential customers on flat billing rates?

f) The Elster model REX-R2SD does not appear to be a current product offering. Is this the same model as the REX2 listed here? https://www.elstersolutions.com/en/product-details-na/826/en/REX2_meter If not, please provide the meter documentation and specifications for the REXR2SD.

g) Is the REX-R2SD used for all residential rate classes? Is it used for both bidirectional billing metering for solar customers and for generation production meters for solar customers?

h) If the Company uses other typical models aside from the REX-R2SD for bidirectional billing metering for solar customers and for generation production meters for solar customers, please provide those models.

i) Why does the Production meter cost substantially less than the Standard meter?

j) What is included in the cost category "Shop Cost"?

k) How long does it take to install a "standard" meter?

l) How long does it take to install a "bi-directional" meter?

Witness: Leland Snook

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
SEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 12, 2020

SEIA 7.1 (continued):

m) How are costs for installation labor determined? Are they based on the actual time it takes to install the meter, or on some other allocator such as meter cost?

n) Confirm that the meter costs listed in SEIA 2.6d are actual costs from the Company's vendor for these units. If they are anything other than this cost, please indicate how these costs were determined.

Response:

a) Generation production meter data is not used in billing.

b) Yes.

c) Yes. As noted in the Company's response to SEIA 7.1 a, data from the production meter is not used for billing. However, it is used to determine performance-based incentives for solar customers, to study and monitor the grid impacts from distributed solar, to calculate the Company's Lost Fixed Cost Recovery adjustment, to calculate cost of service, and to track compliance with regulatory mandates. In addition, the Commission requires APS to utilize production meters for compliance purposes. Please see Decision No. 72737 (January 18, 2012).

d) A new standard meter has such capability. However, the existing standard meters deployed in the field are not capable of supporting bi-directional for all of the Company's types of rates and, therefore, are not used for that purpose.

e) No, because the different rates do not require a different meter type. The cost allocation for meters is provided in workpaper LRS_WP4DR. The monthly service charges vary by rate class. See workpaper JEH_WP1DR.

f) Yes.

g) It is used in all rate classes, but not for bi-directional metering. It is used for the peoduction meter, but without the remote disconnect switch, which makes it less expensive than the standard meter.

h) APS uses the following meters for residential customers:

Residential: Honeywell REX2, Honeywell A3-ILN, Landis+Gyr Focus AXe

Witness: Leland Snook

Response to SEIA 7.1 (continued):

Residential Bi-Directional: Honeywell A3-ILN, Landis+Gyr Focus AXe, Landis+Gyr S4x

Residential Solar Production: Honeywell REX2, Landis+Gyr Focus AXe

i) Refer to part g.

j) The "shop cost" is based on the actual employee classification and time involved to complete preparing and testing the meters.

k) For self-contained meters it takes approximately 10 minutes excluding travel to exchange the meter.

l) Installation of a bi-directional meter is the same as a standard meter, except that typically APS would also set the additional production meter during the same visit.

m) Installation costs are determined by the job classification and the time it takes to perform the work.

n) Yes.

Witness: Leland Snook

Attachment KL-24, SEIA 31.1

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
THIRTY FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
AUGUST 25, 2020

SEIA 31.1: Please refer to the Company's response to SEIA 2.7, SEIA 7.1, SEIA 11.5, and SEIA 23.5.

a) When were performance-based incentives last provided to residential solar customers?

b) Has the Company ever requested a waiver to the regulatory reporting requirements for Renewable Energy Standard Tariff? If so, please provide each waiver that has been requested and approved.

c) Please provide the last 5 years of Renewable Energy Standard Tariff compliance reports that were developed based on production meter reads.

d) Please provide the last 5 years of compliance reports for any other regulatory mandate that were developed based on production meter reads.

e) Please provide the cost breakdown for each of the following meter models as shown in the table response to SEIA 11.5

I. Honeywell REX2
II. Elster R2S
III. Elster R2SD
IV. Honeywell A3-ILN
V. L+G S4x

f) It appears that a substantial share of customers on the R-2, R-3, and RTOU-E tariffs have the L+G Focus Axe meter, which is substantially less expensive than the bi-directional meter cost shown in SEIA 11.5. Why does the Company continue to exclusively use the higher bi-direction meter cost in its LRS_WP4DR TY Development of Allocation Factors Report for solar customers rather than a weighted average cost that includes some higher cost meters and some lower cost meters?

g) Is there any plan to upgrade more sections of the Company's AMI system so that the L+G Focus Axe meter would be compatible in more areas? If so, what is the timeline for this upgrade?

h) For the R2, R3, and R-TOU-E rates in attachment SEIA 23.5_APS19RC01798_Residential Meter Information, please indicate how many customers using each meter have solar installed.

Witness: Jessica Hobbick

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
THIRTY FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
AUGUST 25, 2020

Response to SEIA 31.1:

a) APS has not offered production-based incentives to residential customers at any time.

b) Yes. Please see the table below for the requested and approved waivers.

Type of Waiver	Requested	Approved
Residential DG Carve-Out Requirement	2017 RES Implementation Plan Docket No. E-01345A-16-0238	Decision No. 76312
Residential DG Carve-Out Requirement	2018 RES Implementation Plan Docket No. E-01345A-17-0224	Decision No. 76771
Residential DG Carve-Out Requirement	2019 RES Implementation Plan Docket No. E-01345A-18-0226	Decision No. 77463
Residential DG Carve-Out Requirement	2020 RES Implementation Plan Docket No. E-01345A-19-0148	Pending Approval
Residential DG Carve-Out Requirement	2021 RES Implementation Plan Docket No. E-01345A-20-0199	Pending Approval

c) Please see the following attached documents:

2015 RES Compliance Report	APS19RC02055
2016 RES Compliance Report	APS19RC02056
2017 RES Compliance Report	APS19RC02057
2018 RES Compliance Report	APS19RC02058
2019 RES Compliance Report	APS19RC02059

d) No other Commission renewable mandate relies upon production meter data. APS does, however, use production meter data for the Lost Fixed Cost Recovery Mechanism (LFCR).

e)
I. Honeywell REX2 - $95.84
II. Elster R2S - $95.84
III. Elster R2SD - $141.23
IV. Honeywell A3-ILN - $378.35
V. L+G S4x - $336.84

f) The term "substantial" used in the question is inaccurate. As noted in the Company's response to SEIA 23.5, APS began deploying the L&G Focus Axe meter in January 2019, which is only six months before the end of the Test Year. The meter information referenced in the question pertains to

Response to SEIA 31.1 (contin

meter counts as of July 2020, which is one year after the end of the Test Year. Therefore, while some of the L&G meters were installed prior June 2019, the Honeywell A3-ILN meter represents the predominant bidirectional meter that was in service during the Test Year.

g) No. There is a new bi-directional Honeywell meter, compatible with the current Elster network, that APS is currently assessing with the possibility of deployment as early as late 2020 that is cost competitive to the L+G Focus Axe.

h) Please see the below table for the requested information.

Rate Schedule	Manufacturer	Model	Meter Count
R-2	ELSTER	A3 ILN	865
R-2	ELSTER	R2SD	9
R-2	L+G	FOCUS	2,581
R-2	L+G	S4X	9
R-3	ELSTER	A3 ILN	1,020
R-3	ELSTER	R2SD	4
R-3	L+G	FOCUS	3,442
R-3	L+G	S4X	38
R-TOU-E	ELSTER	A3 ILN	8,127
R-TOU-E	ELSTER	R2S	1
R-TOU-E	ELSTER	R2SD	114
R-TOU-E	ITRON	C12.19	8
R-TOU-E	L+G	FOCUS	15,848
R-TOU-E	L+G	S4X	42
Grand Total			**32,108**

Attachment KL-25, Staff 14.15.

ARIZONA CORPORATION COMMISSION STAFF'S
FOURTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 1, 2020

Staff 14.15: Please provide the approximate number and percentage of APS customers who own, rent, or lease an Electric Vehicle.

Response: Based on the EPRI study referenced in Staff 14.16, there are approximately 16,500 electric vehicles (EVs) registered in the APS service territory. This includes approximately 11,000 all-electric EVs and 5,500 plug-in hybrid EVs.

The Company is not able to track ownership status of EVs located in its service territory.

Witness: TBD

Attachment KL-26, SEIA 5.5d.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 6, 2020

SEIA 5.5: Please refer to the Company's present and proposed R-TOU-E, R-2, R-3, and RTech tariffs, workpaper JEH-WP1DR (Proof of Revenue), workpaper LRS_WP4DR (Development of Allocation Factors Report) and Initial 1.31_APS19RC00282 (2018-19 Load Research Report).

a) Confirm, separately, whether the present and proposed R-TOU-E, R-2, R-3, and R-Tech tariffs were designed to be revenue-neutral with respect to the entire residential class. If they were not, please explain if revenue neutrality was incorporated into the tariff designs.

b) The R-2 and R-3 tariffs collect distribution revenues in part through on-peak demand charges and do not have off-peak demand charges. However, some distribution costs were allocated to these classes based on non-peak demand charges (for instance, all costs based on the sum of individual max (which are necessarily untimed); and in some cases the class NCP occurred during nonpeak hours, such as with the combined R-2 and R-3 class (R-Solar (Demand)). Does the Company see any conflict between allocating costs based in part on off-peak demand values, but collecting revenue through on-peak demand charges?

c) What principles guided the Company when determining what fraction of demand-based distribution costs were collected through volumetric per kWh rates? How did the Company apply these principles differently for the RTOU-E, R-2, R-3, and R-Tech tariffs?

d) The R-Tech tariff had only 29 customers as of the end of the test year, yet the Company has authorization to allow 10,000 customers on this tariff since its approval in August 2017. Why does the Company feel that customer adoption to this rate has been particularly slow? Does the Company plan to make any changes to this tariff to increase customer adoption?

Response: a) No. In the prior rate case, the new rates were calibrated with the revenue from their most similar old rate and then the resulting revenue from all rates was calibrated to the revenue target for the entire residential class. For example, Rate Schedule TOU-E was calibrated to the revenue of the existing time-of-use energy rates, and Rate Schedules R-2 and R-3 were calibrated to the existing demand rates. The R-Tech rate was negotiated and, therefore, not specifically

Response to SEIA 5.5 (continued):

tied to any rate class. However, it was generally checked against Rate R-3 for reasonableness. In the current rate case, the proposed charges were designed to meet revenue targets for each rate.

b) No. Please refer to the Company's response to SEIA 4.8.d.

c) Ideally, the unbundled delivery costs would be entirely recovered through a demand charge or a combination of demand and monthly service charges, in order to fully reflect the drivers for these capacity costs. However, for customer impact considerations, a portion of these costs are recovered through energy charges to limit the overall bundled demand charge. The delivery charges are the same for R-2 and R-3. R-tech recovers a higher percentage of delivery costs through demand charges. TOU-E does not have demand charges.

d) While not definitively known at this time, the low participation to date could have several causes including the attractiveness of Rate Schedule TOU-E to solar customers, low adoption of residential battery storage, or the requirement to purchase new technologies, among other potential reasons. The Company is monitoring customer participation in this rate as part of the pilot program and may propose to modify or discontinue this rate in a future proceeding.

Attachment KL-27, SEIA 19.1.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
NINETEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 7, 2020

SEIA 19.1: Please refer to the Company's 2018-2019 Load Research Report, the Proof of Revenue workpaper, and the Redlined Tariff. If one calculates monthly bills for an average customer using the Total Residential class billing determinants (calculated by taking the total class energy/demand and dividing by the number of customers each month) for the current R-3 and R-TOU-E rates, there is a sizable difference in the results. The R-3 rate produces an average monthly bill of $102, while the R-TOU-E produces an average monthly bill of $140, 37% higher. Further, the Proof of Revenue workpaper shows an average present residential revenue of $130 per customer. The Company can validate these results, but even if it does not choose to do so, please answer the following:

a) Confirm that residential customers can choose either the R-3 or R-TOU-E rates with no restrictions. If deny, please indicate what restrictions exist on these rates.

b) Confirm that the Company did not propose structural changes to the R-3 or R-TOU-E rates in this case, but instead increased the rates by roughly 2.24%. If deny, please indicate where the Company redesigned the rates to attain a specific revenue target other than the average increase applied to the residential class.

c) Confirm that the Company actively advises customers which rate could provide the lowest bill for customers. If deny, please explain.

d) Does the Company actively encourage customers to switch to demand based rates such as the R-3 rate?

e) Does the Company consider three-part rates such as the R-3 rate to be superior to volumetric TOU rates such as the R-TOU-E rate in terms of cost causation and price signaling?

f) Confirm that the R-Basic Large and R-Basic rates have seen sizable customer attrition, while the R-2 and R-3 rates have seen sizable customer growth during the test year.

g) For the average customer using the Total Residential billing determinants, why did the Company design the R-3 rate to provide a nearly 22% discount ($102 vs. $130) to the present average revenue collected per customer?

h) For the average customer using the Total Residential billing determinants, why did the Company design the R-TOU-E

SEIA 19.1 (continued):

rate to provide a nearly 8% premium ($140 vs. $130) to the present average revenue collected per customer?

i) Does the Company believe it is appropriate to offer rates that will produce such large differences in average bills for the average residential customer? If so, please explain why offering rates that are not revenue neutral with respect to the entire residential class is appropriate.

j) If every customer were to switch to the R-3 rate, the Company would have collected roughly $1.35 billion from the residential class based on the present rates. If every customer were to switch to the R-TOU-E rate, the Company would have collected roughly $1.87 billion from the residential class based on the present rates. The Company's current revenue on the present rates is $1.74 billion.

i. What are the ramifications of offering a rate that is available to all customers that could result in the Company under-collecting residential revenue by roughly $400 million?

ii. What are the ramifications of offering a rate that is available to all customers that could result in the Company over-collecting residential revenue by roughly $130 million?

iii. If customers switch to the R-3 tariff at a rate that exceeds the Company's modeling expectations in this rate case, how will the loss in revenue be handled?

iv. If customers switch to the R-TOU-E tariff at a rate that exceeds the Company's modeling expectations in this rate case, how will the over-collection of revenue be handled?

Response:

a. Confirmed. Other than the allowed frequency of rate changes.

b. The Company added a super-off-peak pricing period for winter months to rate R-3. There were no proposed structural changes to rate R-TOU-E. All residential rate classes are proposed to increase by the same percent. Please refer to the Company's response to SEIA 3.20.a.

c. Yes. The Company advises customers which rate could provide the lowest bill using past usage data.

Response to SEIA 19.1 (continued):

d. The Company encourages customers to move to what could be their most economical rate plan and educates customers on the demand rate concept and how to save on the rate.

e. Yes. The on-peak demand charges are better aligned with the demand-related cost drivers. While time-of-use energy rates are a better reflection of costs than flat energy rates, they do not incent the consistent reduction in peak usage throughout the month, as do demand rates, that is required to effectively reduce demand-related costs. For example, please see the Company's response to SEIA 5.5.

f. Confirmed. The changes in customer participation during the Test Year are reflected in the revenue proforma for customer annualization. Please see workpaper LRS_WP9DR.

g. The comparison in the question is invalid. The residential rate classes each have a different unit cost of service because the participants have different demand, energy, and customer related cost requirements. The rates for each class are designed to reflect the costs of the participants of that class, not the average residential participant. Rate R-3 has a lower unit cost to serve compared to other classes because the customers have a higher monthly energy usage, which spreads the fixed customer costs over more kWh and they have a higher load factor, which spreads the demand-related costs over more kWh. Please refer to the Company's response to SEIA 11.1.

h. The current R-TOU-E rate recovered roughly 95% of its cost of service for the Test Year, which is somewhat higher than the demand and basic rates, but less than 100%. In the last rate case, the R-TOU-E rate design was adjusted to produce a certain expected benefit to new solar customers, as negotiated in the Settlement Agreement in that case. In this rate case, the R-TOU-E rate is proposed to be increased by the average residential amount.

i. Yes. Please see the Company's response to parts g and h.

j.
   i. It would be neither practical nor economical for all customers to switch to any one rate. Therefore, the scenario in the question would not occur. In the last rate case, the rate designs considered the design and

Response to SEIA 19.1 (continued):

cost of service for similar legacy rates and the expected revenue from the customers that were likely to participate in the new rate. In addition, the actual participation in residential rates has been consistent with the expected participation in the last rate case.

ii. Please see the Company's response to part i.

iii. The rates in this rate case were not based on modelling assumptions, but rather on actual Test Year participation and billing determinants for each rate. Furthermore, after a rate case is completed and new rates are authorized by the Commission, any subsequent changes in costs or revenues cannot be reflected in rates until the next rate case.

iv. Please see the Company's response to part j, subpart iii.

Witness: Jessica Hobbick

Attachment KL-28, SEIA 16.3.

SOLAR ENERGY INDUSTRY ASSOCIATION'S SIXTEENTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 JUNE 29, 2020

SEIA 16.3: Please refer to Rate Schedule R-XS and R-S. Why are customers on these tariffs not allowed to install DG systems and remain on these tariffs?

Response: The Settlement in the last rate case required non-grandfathered solar customers to be served under a time-of-use or demand rate. R-XS and R-Basic are flat rates and therefore are not available to solar customers. The Company interprets "R-S" to mean R-Basic.

If these schedules were open to solar customers, the schedules would need to change to avoid increasing the existing cost shift from solar residential customers to non-solar residential customers, such as including a grid access charge.

Witness: Jessica Hobbick

Attachment KL-29, SEIA 4.5a.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 4, 2020

SEIA 4.5: Please refer to JEH-WP1DR (Proof of Revenue).

a. Provide all workpapers and analysis that were used to develop the specific value of the present grid access charge for TOU-E customers of $0.93 per kW DC.

b. Please provide a narrative discussion of how this value was calculated and what costs are intended to be collected through the grid access charge for solar customer on the TOU-E rate.

Response:

a. The present grid access charge was developed and approved by the Arizona Corporation Commission as part of a settlement in the prior rate case, Docket No. E-01345A-16-0036, et. al. The approved amount was the result of negotiations and therefore not derived from any specific cost basis. The charge was instead set to provide a certain level of expected bill savings per kWh to solar customers. Please see Attachment ExcelAPS19RC00532.

b. Please see APS's response to 4.5a. The charge was adopted to help address the $1 billion cost shift from residential solar customers to other customers as the result of the solar customers paying less than their cost of service. Refer to Docket Nos. E-013451-16-0036 et. al. and E-00000J-14-0023.

Witness: Jessica Hobbick

Attachment KL-30, SEIA 9.11

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
NINTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 19, 2020

SEIA 9.11: Please refer to the Company's response to SEIA 5.8.

a) Confirm that the Proof of Revenue workpaper JEHWP1DR contains a revenue requirement for each class based on the Company's current COSS, which Is based on the Company's current cost allocators, which are in turn based on site load for solar customers. If deny, please explain.

b) Confirm that altering the cost allocators in the LRS_WP4DR TY Development of Allocation Factors Report to be based on delivered load instead of site load would change the values of the cost allocators. If deny, please explain.

c) Confirm that changing the cost allocators would change the revenue requirement for each class in the COSS. If deny, please explain.

d) Please explain the proper steps to ensure that new allocation factors based on delivered load will properly update the COSS revenue requirements for each class, which can then subsequently be used to design a rate using the Proof of Revenue workpaper.

Response:

a. Deny. The site load and credit method was used in the cost-of-service study to appropriately determine the gap between Test Year revenues and costs for the solar rate classes. This gap is based on both the site load and the credits, not just the site load as claimed by the question. Furthermore, the revenue targets for the proposed solar legacy rates are below cost-of-service, as agreed to in the Settlement Agreement and authorized by the Commission in the prior rate case. The proposed solar grid access charge for residential rate R-TOU-E in the proof-of-revenue is also below cost-of-service. A further discussion on the revenue targets in the proof of revenue is provided in the Direct Testimony of APS witness Jessica Hobbick, pages 3-4.

b. Yes, it would change the values but it would be wrong. Please see APS's response to SEIA 9.7.

c. Deny. Such a change would only impact the residential solar rate classes and the resulting revenue requirement would be incorrect. Please see APS's response to part b.

Witness: Leland Snook

SEIA 9.11 Continued Response:

d. The Company does not have any specific advice because the analysis would be incorrect. For general steps on changing a proposed rate please see APS's response to SEIA 5.8.

Witness: Leland Snook

Attachment KL-31, SEIA 12.2.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
TWELFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
MARCH 11, 2020

SEIA 12.2: Please refer to the Company's response to SEIA 9.11a and SEIA 4.5a. In SEIA 4.5a, which requested "all workpapers and analysis that were used to develop the specific value of the present grid access charge for TOU-E customers of $0.93 per kW DC", the Company admitted that "The approved amount was the result of negotiations and therefore not derived from any specific cost basis." Given this, how can the Company claim in SEIA 9.11a that "The proposed solar grid access charge for residential rate R-TOU-E in the proof-of-revenue is also below cost-of-service."?

Response: The Company's responses are accurate. The currently effective negotiated grid access charge is significantly below the actual cost of service for this charge. The requested increase, which is the same as that requested for the average residential class, would not materially bridge this gap.

In the prior rate case, the Company provided information showing that the revenues from solar customers on energy rates only recovered 38% of their cost of service, compared to 92% for residential customers as a whole. This gap amounted to an annual revenue deficit of $865 per solar customer, or roughly $72 per month. Given a typical solar installation of 7 kW, a grid access charge of over $10 per kW per month could have been justified.

Witness: Leland Snook

Attachment KL-32, SEIA 5.6f.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 6, 2020

SEIA 5.6: Please refer to the Company's proposed R-TOU-E, R-2, and R-3 tariffs and workpaper JEH-WP1DR Proof of Revenue.

a) Which of these three tariffs does the Company feel best reflects cost-causation principles?

b) Would the Company feel that a tariff that exactly translates cost allocation factors to a rate design (e.g. a tariff in which customer, on-peak and off-peak energy, CP, NCP, and Ind Max demand costs are mapped exactly to tariff components based on an individual's energy and demand characteristics) be appropriate? If so, please indicate why the customer has not proposed such a rate. If not, please indicate why.

c) In the "TY kWh,Rev,Cust" tab, do the kWh billed figures use the "site" or "delivered" kWh for the solar customers within the three tariffs?

d) In the "TY kWh,Rev,Cust" tab, is the "kWh unbilled" values related in any way to the difference between "site" and "delivered" for solar customers within these tariffs? If so, please explain if the difference is wholly attributable to this difference.

e) Confirm that solar customers on the R-2 and R-3 tariffs do not have a grid access charge, but solar customers on the R-TOU-E tariff do have a Grid Access Charge.

f) Confirm that in JEH-WP1DR, the total cost allocated to the R-TOU-E customer class is recovered through the kWh and customer billing determinants, and none is recovered through the Grid Access Charge line item. If deny, please indicate where in the Proof of Revenue workpaper the costs recovered through the Grid Access Charge line item.

g) How much does the Company project it will collect annually through the Grid Access Charge?

h) Where is the revenue from the Grid Access Charge accounted for in the Proof of Revenue workpaper or COSS workpaper?

i) It appears that the billing determinants in the Proof of Revenue workpaper are based on the "delivered" kWh from solar customers plus the "no solar" kWh for the R-TOU-E load study. Assuming this is the case, and given that the

Witness: Jessica Hobbick

SEIA 5.6 (continued): Company will recover the entire revenue requirement from the R-TOU-E class based on the delivered energy, explain how revenue collected through the Grid Access Charge is not in excess of the costs allocated to the R-TOU-E customer class?

Response:

a) Each of these rates are designed to recover the costs allocated to that class, and reflect cost causation principles. However, Rate Schedule R-3 has best alignment of charge types with cost drivers because it recovers more of the demand-related capacity costs through demand charges.

b) No. This would require a separate rate for each residential customer, which would not be practical.

c) Delivered.

d) No. The term "unbilled" refers to accrual adjustments for the Test Year.

e) Correct. Rates R-2 and R-3 do not have a grid access charge because they recover a portion of their capacity costs through demand charges.

f) Correct. The Grid Access Charge revenue is credited against the revenue requirement for the LFCR Adjustor Rate, which is not part of base rates. Therefore, it is not included in the proof-of-revenue in this proceeding. The associated costs are also removed from the cost-of-service-study.

g) The Company does not project revenue collected through the Grid Access Charge. The Test Year revenue was approximately $734 k.

h) Please see part f.

i) Please see part f.

Attachment KL-33, SEIA 5.6e.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 6, 2020

SEIA 5.6: Please refer to the Company's proposed R-TOU-E, R-2, and R-3 tariffs and workpaper JEH-WP1DR Proof of Revenue.

a) Which of these three tariffs does the Company feel best reflects cost-causation principles?

b) Would the Company feel that a tariff that exactly translates cost allocation factors to a rate design (e.g. a tariff in which customer, on-peak and off-peak energy, CP, NCP, and Ind Max demand costs are mapped exactly to tariff components based on an individual's energy and demand characteristics) be appropriate? If so, please indicate why the customer has not proposed such a rate. If not, please indicate why.

c) In the "TY kWh,Rev,Cust" tab, do the kWh billed figures use the "site" or "delivered" kWh for the solar customers within the three tariffs?

d) In the "TY kWh,Rev,Cust" tab, is the "kWh unbilled" values related in any way to the difference between "site" and "delivered" for solar customers within these tariffs? If so, please explain if the difference is wholly attributable to this difference.

e) Confirm that solar customers on the R-2 and R-3 tariffs do not have a grid access charge, but solar customers on the R-TOU-E tariff do have a Grid Access Charge.

f) Confirm that in JEH-WP1DR, the total cost allocated to the R-TOU-E customer class is recovered through the kWh and customer billing determinants, and none is recovered through the Grid Access Charge line item. If deny, please indicate where in the Proof of Revenue workpaper the costs recovered through the Grid Access Charge line item.

g) How much does the Company project it will collect annually through the Grid Access Charge?

h) Where is the revenue from the Grid Access Charge accounted for in the Proof of Revenue workpaper or COSS workpaper?

i) It appears that the billing determinants in the Proof of Revenue workpaper are based on the "delivered" kWh from solar customers plus the "no solar" kWh for the R-TOU-E load study. Assuming this is the case, and given that the

Witness: Jessica Hobbick

SEIA 5.6 (continued): Company will recover the entire revenue requirement from the R-TOU-E class based on the delivered energy, explain how revenue collected through the Grid Access Charge is not in excess of the costs allocated to the R-TOU-E customer class?

Response:

a) Each of these rates are designed to recover the costs allocated to that class, and reflect cost causation principles. However, Rate Schedule R-3 has best alignment of charge types with cost drivers because it recovers more of the demand-related capacity costs through demand charges.

b) No. This would require a separate rate for each residential customer, which would not be practical.

c) Delivered.

d) No. The term "unbilled" refers to accrual adjustments for the Test Year.

e) Correct. Rates R-2 and R-3 do not have a grid access charge because they recover a portion of their capacity costs through demand charges.

f) Correct. The Grid Access Charge revenue is credited against the revenue requirement for the LFCR Adjustor Rate, which is not part of base rates. Therefore, it is not included in the proof-of-revenue in this proceeding. The associated costs are also removed from the cost-of-service-study.

g) The Company does not project revenue collected through the Grid Access Charge. The Test Year revenue was approximately $734 k.

h) Please see part f.

i) Please see part f.

Witness: Jessica Hobbick

Attachment KL-34, RUCO 2.1

RESIDENTIAL UTILITY CONSUMER OFFICE'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 JANUARY 14, 2020

RUCO 2.1: Re: Hobbick Direct at page 3, with respect to Ms. Hobbick's proposal to introduce a super off-peak period for rate classes R-2, R-3 and E-221, please provide the total hourly retail load for APS by hour for the years 2017-2019 inclusive and 2016 through October 1, 2016 through December 31, 2016. We request that the data should be in Excel with a cell unlocked.

Response: Attached in native file format as ExcelAPS19RC00321 is APS's hourly total retail load for the period October 1, 2016 through June 30, 2019.

Witness: Jessica Hobbick and Brad Albert

Attachment KL-35, SEIA 3.10.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 30, 2020

SEIA 3.10: Please refer to the Company's response to RUCO 2.1.

a. Confirm whether the data represents the gross system load (that is, before any load that is met through on-site solar) or the net system load (that is, after any load is met through on-site solar).

b. Please provide the hourly retail system load for 2016 and 2019 containing the same data as was provided in RUCO 2.1.

c. Please provide the hourly retail system load for 2016, 2017, 2018, and 2019 that contains the either the gross system load (if RUCO 2.1 contains the net system load) or the net system load (if RUCO 2.1 contains the gross system load).

Response:

a. The data included in RUCO 2.1 is net system load.

b. The hourly retail system load for 2016 is included in attachment ExcelAPS19RC00384. January through June of 2019 was provided in response to RUCO 2.1. The hourly retail system load for July through December of 2019 is not currently available, but will be provided when complete.

c. The gross system retail load is included in ExcelAPS19RC00385 for January of 2016 through June of 2019. The hourly retail system load for July through December of 2019 is not currently available, but will be provided when complete.

Witness: Leland Snook

Attachment KL-36, SEIA 7.10c

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
SEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 12, 2020

SEIA 7.10: Please refer to the Company's response to SEIA 3.14, attachment SEIA 3.14_APS19RC00390_Miessner Direct Testimony 16-0036. On page 27 to 30, Mr. Miessner discusses the Company's demand measurement proposal, including limiting billing demand to a 15% load factor equivalent value.

a) Confirm that the Company's current and proposed tariffs utilize the demand measurement proposal discussed in this attachment. If not, please indicate what the current measurement methodology is.

b) For customers on a demand rate in 2017 through 2019, inclusive, please provide the monthly number of customer bills and percentage of customer bills in which the demand limiter was utilized. Please also provide the average reduction from the measured billing demand to the demand limited billing demand for each month.

c) The testimony states "This demand limiter will not be applicable to partial requirements customers with on-site generation." Why was the demand limited not extended to partial requirements customers with on-site generation?

d) Given that the Company requires metering that allows the Company to determine the "gross" or "site" usage for a partial requirements customer, could the Company implement a demand limiter that is based on a 15% load factor equivalent for the "gross" or "site" usage for a partial requirements customer?

e) Would the Company consider implementing a demand limited discussed in c) above for partial requirements customers? If not, why not?

f) Please provide additional data and/or reports that were generated as part of the Flagstaff Solar Experiment discussed on page 42.

Response:

a) The current and proposed residential Rates R-2 and R-3 have this provision for full requirements customers.

b) The Company has not performed this specific analysis. The monthly billing demand and energy information provided in the response to SEIA 2.3 could be used to obtain an upper estimate of this value.

Witness: Leland Snook

Response to SEIA 7.10 (Continued):

c) The demand limiter was designed in case a customer occasionally sets an unusually high demand, relative to their energy usage, in a particular month. It was not meant for solar customers who typically set a high demand relative to their energy usage in every month.

d) The Company does not calculate the bills of residential solar customers based on the site load. Therefore, it would be inconsistent to reduce a billed amount by a calculation based on the site load.

e) No. See parts c and d.

f) Along with other entities, APS won a US Department of Energy – DOE Solar Energy Technologies Program's High Penetration Solar Deployment award to demonstrate and study high photovoltaic penetration. As part of the Company's approved Flagstaff Community Power Project (Project), APS developed, constructed and managed a high penetration of distributed photovoltaic generation in Flagstaff, Arizona. At the conclusion of Phase 1 of the DOE study, the DOE issued a technical report which can be found here:
https://www.osti.gov/servlets/purl/1025589
A Phase 1 update authored by the National Renewable Energy Laboratory (NREL, one of the Company's partners in the DOE study) can be found here:
https://www.nrel.gov/docs/fy12osti/54110.pdf
The DOE technical report on Phases 2 through 5 of the study can be found here:
https://www.osti.gov/servlets/purl/1171386

In addition, APS was required to report on the progress of the Flagstaff Project in its annual Renewable Energy Standard compliance reports until its completion. Those reports can be found here:
https://docket.images.azcc.gov/0000124264.pdf
https://docket.images.azcc.gov/0000135558.pdf
https://docket.images.azcc.gov/0000143938.pdf
https://docket.images.azcc.gov/0000152762.pdf

Attachment KL-37, SEIA 24.1b.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
TWENTY FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 14, 2020

SEIA 24.1: Please refer to the Company's response to SEIA 7.10.

a) Please provide the amount that was under-billed on the R-2 and R-3 tariffs due to the difference between a customer's actual billing demand and the 15% load-factor billing demand limiter.

b) Is there a limit to how many times per year a customer can trigger the 15% load-factor demand limiter?

c) Does the Company provide any information to the customer whether they have hit the 15% load-factor demand limiter? If so, please provide an example of the communication.

d) 7.10c states that the demand limiter "was not meant for solar customers who typically set a high demand relative to their energy usage in every month." Please provide all analyses that the Company has performed that indicate individual solar customers "typically set a high demand relative to their energy usage in every month." Provide all workpapers in their original format with formulas intact.

Response:

a) There was no "under billing." The R-2 and R-3 rate schedules were billed as approved by the Commission, with the demand limiter provision. The Company interprets this question to ask: what was the total annual bill reduction resulting from the demand limiter provision? These amounts are provided below.

R-2:	$377,975
R-3:	$680,916

b) No.

c) Yes. The Company provides both the read demand and the billing demand on the bill. Please see attachment APS19RC01760 for an example.

d) Please see the information provided in the Company's response to initial 1.31. For example, the average monthly class load factor for the R-3 solar customers' delivered load, based on the on-peak demand, is 28%, which is significantly lower than the 42% result for non-solar customers on the R-

Witness: Leland Snook

Attachment KL-38, SEIA 24.1d.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S TWENTY FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 14, 2020

SEIA 24.1: Please refer to the Company's response to SEIA 7.10.

a) Please provide the amount that was under-billed on the R-2 and R-3 tariffs due to the difference between a customer's actual billing demand and the 15% load-factor billing demand limiter.

b) Is there a limit to how many times per year a customer can trigger the 15% load-factor demand limiter?

c) Does the Company provide any information to the customer whether they have hit the 15% load-factor demand limiter? If so, please provide an example of the communication.

d) 7.10c states that the demand limiter "was not meant for solar customers who typically set a high demand relative to their energy usage in every month." Please provide all analyses that the Company has performed that indicate individual solar customers "typically set a high demand relative to their energy usage in every month." Provide all workpapers in their original format with formulas intact.

Response:

a) There was no "under billing." The R-2 and R-3 rate schedules were billed as approved by the Commission, with the demand limiter provision. The Company interprets this question to ask: what was the total annual bill reduction resulting from the demand limiter provision? These amounts are provided below.

R-2:	$377,975
R-3:	$680,916

b) No.

c) Yes. The Company provides both the read demand and the billing demand on the bill. Please see attachment APS19RC01760 for an example.

d) Please see the information provided in the Company's response to initial 1.31. For example, the average monthly class load factor for the R-3 solar customers' delivered load, based on the on-peak demand, is 28%, which is significantly lower than the 42% result for non-solar customers on the R-

Witness: Leland Snook

Response to SEIA 24.1 (continued):	3 rate. This result means that the solar customer purchases significantly less energy from APS relative to their demand compared with non-solar customers on the same rate.

Attachment KL-39, SEIA 3.14

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 30, 2020

SEIA 3.14: Please provide a narrative description of the analyses and process that were used when updating the residential on-peak hours from 12 PM to 7 PM in 2016 to 3 PM to 8 PM in 2017. Please provide a link to the docket and specific testimony that supported this change.

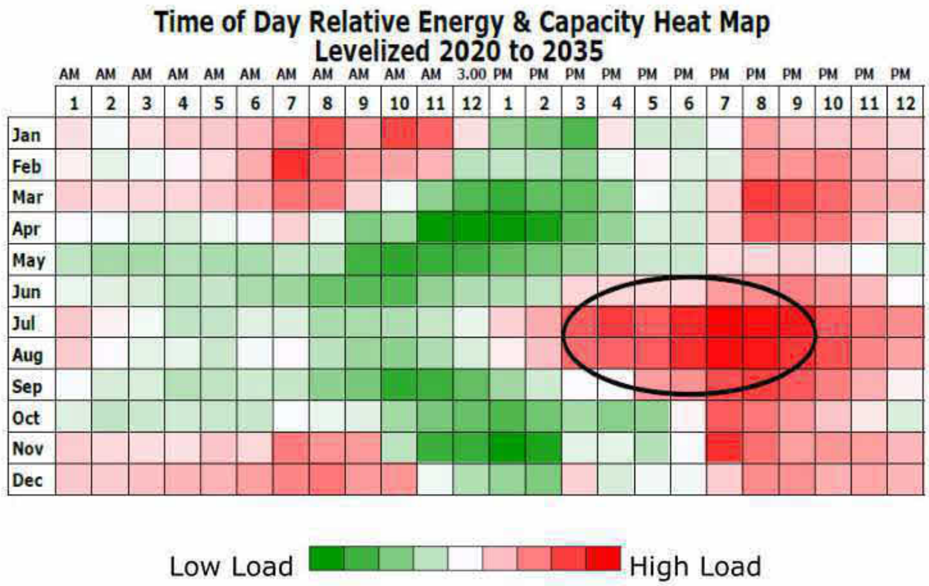
Response: The Company considers several factors when proposing to change Time-Of-Use (TOU) hours, all of which were assessed in the proposed changes in the last rate case. These factors include a rigorous review of hourly system loads, costs and critical hours to identify core on-peak hours where loads, wholesale market costs and loss-of-load probabilities are high. This analysis is done for both current and forecasted loads.

The non-coincident class peaks are also reviewed because the TOU rates typically provide on-peak rates for delivery costs, which are driven by non-coincident class peaks and individual customer demands. Generation and transmission costs are driven by the system peak. Ideally, both the system peak and class peak would be within the on-peak hours.

In addition, there are practical customer considerations to consider when designing TOU rates. Seasonal changes in on-peak hours, contiguous blocks for on-peak hours, metering and billing issues and customer impacts should be assessed. For example, in the prior rate case, the analysis showed that the summer system load was relatively high on Saturdays. However, APS proposed on-peak hours of 3 pm to 8 pm on weekdays only due to customer considerations.

Figure 2 from Charles Miessner's Settlement Rebuttal Testimony in the Company's most recent rate case (Docket No. E-01345A-16-0036 et. al.) provides APS's analysis of on-peak hours:

Response to SEIA 3.14 (continued):



Ideally, TOU hours should also be relatively stable over time and only changed infrequently as necessary in order to give customers time to understand and adapt to the rates. The prior time-of-use hours of 12-7 pm were in place for 10 years and the legacy 9-9 rates were in place for over 25 years. Therefore, the Company would not recommend any changes to the TOU hours in this proceeding, other than adding the super off peak to the Time-of-use demand rates.

Specific testimony supporting this change includes the Direct and Settlement Rebuttal Testimonies of Charles Miessner and the Direct Testimony of James Wilde in Docket No. E-01345A-16-0036 et. al., which are provided as Attachments APS19RC00390, APS19RC00391 and APS19RC00392 respectively. Additional workpapers are provided as Attachments ExcelAPS19RC00393 and APS19RC00394.

Witness: Jessica Hobbick

Attachment KL-40, SEIA 2.3.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 27, 2020

SEIA 2.3: Please refer to Schedule H-5.

a. For all non-legacy Residential tabs (R-XS through R-TECH by kW), please provide the load data separately for all customers without solar and for all customer with solar. Further, please provide the data in kWh block increments of 50 kWh between 0 and 2,000 kWh and in increments of 100 kWh between 2,000 and 5,000 kWh, and in increments of 500 kWh between 5,000 kWh and 10,000 kWh.

b. In the R-2 by kW, R-3 by kW, and R-TECH by kW tabs, please indicate what measure of demand is listed (e.g. non-coincident peak, on-peak, off-peak, etc.).

c. For all non-legacy Residential tariffs, please provide a matrix with bill counts that has kWh blocks on one axis (in 100 kWh increments through 5,000 kWh and in 500 kWh increments between 5,000 kWh and 10,000 kWh) and demand blocks on the other axis (in 0.4 kW increments between 0 kW and 16 kW and in 1 kW increments between 16 kW and 30 kW).

d. If the Company is not willing to produce the analyses above, provide the raw data that would be required to produce these analyses.

Response:

a. The requested analysis was not performed as part of the Application. See APS's response to SEIA 2.3d.

b. The demand provided is monthly on-peak billing demand by season.

c. The requested analysis was not performed as part of the Application.

d. The requested data is provided as APS19RC00343. Please note that this file is provided in .csv format and, with millions of rows of data, cannot be completely opened in Excel.

Witness: Jessica Hobbick

Attachment KL-41, Vote Solar 1.3.

VOTE SOLAR'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 5, 2020

Vote Solar 1.3: Reference APS's R-2 and R-3 rates:

a. Please identify, by customer (using an anonymized, but consistent customer reference), each month when a full requirements customer's demand charge was "limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month" as provided in the tariff.

b. For each instance identified in response to (a), above, please state: (i) the amount of charge that would have been assessed without limiting the charge to a kW no higher than that which would result in a 15% load factor; and (ii) the charge that was actually assessed.

c. Please identify, by customer (using an anonymized, but consistent customer reference) each month when a DG customer's demand charge would have been lower if it was "limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month."

d. For each instance identified in response to (c), above, please state: (i) the amount of the charge that would have been assessed if the charge had been limited to a kW no higher than that which would result in a 15% load factor; and (ii) the charge that was actually assessed.

Response: a. Please see attachment Excel APS19RC01392.

b. Please see the Company's response to part a.

c. Please see attachment ExcelAPS19RC01393.

d. Please see the Company's response to part c.

Witness: Jessica Hobbick

Attachment KL-42, SEIA 7.10b.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
SEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 12, 2020

SEIA 7.10: Please refer to the Company's response to SEIA 3.14, attachment SEIA 3.14_APS19RC00390_Miessner Direct Testimony 16-0036. On page 27 to 30, Mr. Miessner discusses the Company's demand measurement proposal, including limiting billing demand to a 15% load factor equivalent value.

a) Confirm that the Company's current and proposed tariffs utilize the demand measurement proposal discussed in this attachment. If not, please indicate what the current measurement methodology is.

b) For customers on a demand rate in 2017 through 2019, inclusive, please provide the monthly number of customer bills and percentage of customer bills in which the demand limiter was utilized. Please also provide the average reduction from the measured billing demand to the demand limited billing demand for each month.

c) The testimony states "This demand limiter will not be applicable to partial requirements customers with on-site generation." Why was the demand limited not extended to partial requirements customers with on-site generation?

d) Given that the Company requires metering that allows the Company to determine the "gross" or "site" usage for a partial requirements customer, could the Company implement a demand limiter that is based on a 15% load factor equivalent for the "gross" or "site" usage for a partial requirements customer?

e) Would the Company consider implementing a demand limited discussed in c) above for partial requirements customers? If not, why not?

f) Please provide additional data and/or reports that were generated as part of the Flagstaff Solar Experiment discussed on page 42.

Response:

a) The current and proposed residential Rates R-2 and R-3 have this provision for full requirements customers.

b) The Company has not performed this specific analysis. The monthly billing demand and energy information provided in the response to SEIA 2.3 could be used to obtain an upper estimate of this value.

Witness: Leland Snook

Attachment KL-43, SEIA 16.2.

SOLAR ENERGY INDUSTRY ASSOCIATION'S SIXTEENTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 JUNE 29, 2020

SEIA 16.2: Please refer to Rate Rider EPR-6.

a) What is the maximum power than can be provided by the Company to a residential customer through a 200-amp service? Through a 400-amp service? Through a 600-amp service? Through an 800-amp service?

b) What is the engineering / technical purpose of limiting the nameplate capacity of residential DG systems based on the amperage of the service as found in Generator Requirement 3?

c) What piece of equipment (e.g. line transformer, meter, etc.) is the bottleneck that determines the nameplate capacity limits of the residential DG system as found in Generator Requirement 3?

d) What is the engineering / technical purpose of limiting the nameplate capacity of a DG system over 10 kW to 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve months as found in Generator Requirement 4?

e) What piece of equipment (e.g. line transformer, meter, etc.) is the bottleneck that determines the nameplate capacity limits of the DG system over 10 kW as found in Generator Requirement 4?

f) If a residential customer has installed and is paying for 800-amp service that is able to serve a maximum DG system of 60 kW-dc, and has a peak demand of 20 kW-ac, what basis does the Company have for restricting the size of a DG system to 30 kW-ac? Please explain from both a policy, cost, and engineering perspective.

g) Is the Company aware of other utilities that place similar DG size restrictions on DG systems over 10 kW based on the peak demand of the customer? If so, please provide a list of such utilities.

h) Is the Company aware that other utilities often place DG size restrictions based on the total amount of annual energy that a DG system produces compared to the customer's annual load (such as 100% or 125% of customer annual energy usage)?

Witness: Jessica Hobbick

SEIA 16.2 (continued):

i) Would the Company consider shifting the size requirement to be one based on customer annual energy usage rather than customer maximum one-hour peak demand? If not, please explain why not.

Response:

a) For a typical residential interconnection, the theoretical maximum for a 200-Amp panel serving 120/240 Volt service is 38.4 kW factoring in NEC recommended maximum breaker loading, customer panel configurations and delivery voltages. The maximum load for 400-Amp, 600-Amp, and 800-Amp service are proportional to the panel amperage. In reality, customers use a mix of 120- and 240- Volt circuits for their appliances, so the maximum kW demand from the panel will vary and be lower than 240-volt number.

However, the distribution service equipment is not sized to serve the maximum potential draw from each customer based on their service amperage. Nor is it sized to accommodate solar generators that could potentially export 150% of each customer's maximum load back to the grid. Please refer to the Company's responses to SEIA 5.1, SEIA 5.2, and SEIA 5.3.

A more typical residential installation for 200-amp service would be sized to serve roughly 12.23 kW, which is derived as shown below. The other typical power supplies are: 400-Amp - 24.46 kW, 600-Amp - 36.69 kW, and 800-Amp - 48.92 kW.

Typical power delivery for 200-Amp service

$(200\text{ A}) \times (0.8) \times (0.35) \times (240\text{ V}) \times (0.91) = 12.23\text{ kW}$

Where:

Panel amperage rating (SES): 200 A
NEC safety factor: 0.8
Typical residential demand factor: 0.35
Operating voltage: 240 V
Typical residential load power factor: 0.91

b) Given the significant subsidies for the net metering program, certain size limitations were established in the net metering

Response to SEIA 16.2 (continued):

rules (A.A.C. R-14-2-2302) to ensure that the solar generation was intended to be used to offset the customers usage, rather than to sell power to the utility. Under the Rules, a generator's capacity cannot be greater than 125% of the customers connected load or, in the absence of load data, the service drop capacity.

The Settlement in the last rate case provided, and the Commission authorized, that the provisions in Schedule EPR-6 was a reasonable way to implement the size requirements under the Rules. The guidelines enable the Company to determine the eligibility for rate rider EPR-6 without having to perform load calculations and meter checks for most solar customers, which speeds up the process and reduces program costs. The compromise limits were set above the typical kW demand and below the maximum theorical kW demand for the service amperages. In addition, the overall system size limit was increased to 150% of peak demand, rather than the 125% specified in the Rules.

c) Please see the Company's response to part b for a discussion of how these limits were established.

d) Please see the Company's response to part b for a discussion of how these limits were established.

e) Please see the Company's response to part b for a discussion of how these limits were established.

f) The Company does not charge extra for 800-Amp service. Please see the Company's response to part b for a discussion of how the limits were established.

g) Yes. Both peak load, annual energy and absolute size limits are used in the industry as a basis to set limits on generator sizes under net metering programs. For example, as discussed in the response to part b, all Arizona utilities are subject to the peak-load based limitation required under the net metering rules. Other states are a mix of these limiting methods. For example, North Carolina uses both absolute and demand-based limits, restricting residential net metering to the lower of 100% of peak demand or 20 kW. Pennsylvania, Michigan, and Delaware are examples of jurisdictions that use annual energy as the basis for generator size limits. Iowa is mixed on this issue - some

Response to SEIA 16.2 (continued):

utilities use annual energy, others use peak demand. Wisconsin, Virginia, and South Carolina are examples of jurisdictions that use absolute size limits.

h) Yes. Please refer to the Company's response to part g.

i) No. As discussed in the response to part b, Arizona regulation requires net metering limitation to be based on peak load rather that annual energy. In addition, the Company is not proposing, nor would it support, any changes to the net metering program. The program was closed to new residential customers in the last rate case. In addition, existing grandfathered solar customers cannot increase the size of their systems more than 10% or 1 kW and remain on the program. Therefore, changing any size requirements for participation is moot.

Witness: Jessica Hobbick

Attachment KL-44, SEIA 16.5.

SOLAR ENERGY INDUSTRY ASSOCIATION'S
SIXTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 29, 2020

SEIA 16.5: Please refer to the Company's response to SEIA 2.3, SEIA 8.1, and SEIA 9.1. Please produce a consolidated data file with all of the requested information for all non-residential customers.

Response: Please see the attached .csv file APS19RC01475 for the requested information for non-residential customers. This data file does not include bill accruals.

Witness: Leland Snook

Attachment KL-45, SEIA 26.1.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S TWENTY SIXTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 JULY 20, 2020

SEIA 26.1: Please refer to the Company's response to SEIA 16.2 and the EPR-6 tariff.

a) Confirm that a new non-residential customer who wishes to establish service and install a PV on the EPR-6 tariff and does not have 12 months of prior load information will be allowed to size their system up to the service drop capacity. If deny, please explain how the Company determines the maximum system size for new customers, and how this is in conformance with A.A.C. R14-2-2302 requirement that the system be sized up to the service drop capacity.

b) Does the Company see any inconsistency between allowing a new customer to size their system up to the service drop capacity, but limiting an existing customer's system size to 150% of its past 12 month's peak demand?

c) The Company's estimate for the maximum demand on a 200-amp service is 12.23 kWAC. Was this value used in conjunction with the 125% limit in A.A.C. R14-2-2302 to derive the residential limits for 200-amp service? That is, 12.23 * 1.25 = 15.3 kW, which is very close to 15 kW. If this was not the basis for the residential system size limits, please indicate how the specific limits were established for each amperage level.

Response:

a) Deny. The question misinterprets the maximum size provision under the Net Metering Rules. In the case of a new customer, without sufficient billing history information, the peak load from the previous tenant could be used in certain cases. Otherwise, the peak load would be determined through an electrical load study for the building, provided by the customer.

b) Please refer to the Company's response to part a.

c) Yes.

Witness: Leland Snook

Attachment KL-46, SEIA 26.2.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
TWENTY SIXTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 20, 2020

SEIA 26.2: Please refer to the Company's E-32 tariffs.

a) What is the economic theory supporting the Company's declining block tariffs for energy and demand on the E-32 S and E-32 M and for demand on the E-32 L tariffs?

b) How is a declining block tariff for energy and demand on these tariffs reflective of cost causation principles?

c) Why is the first 100 kW of demand the breakpoint on the E-32 S (21– 100 kW), E-32 M (101 – 400 kW), and the E-32 L (400+ kW) tariffs given these customers serve very different size customers? Is there any significance regarding the 100 kW level?

d) Are the demand meters installed for customers on the E-32 tariffs all capable of recording a 15-minute peak demand value? If not, please indicate which customers or tariffs do not have this capacity.

e) On the E-32 L tariff, the demand ratchet is based on "80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month." Is the "highest kW measured" in this case the highest 15-minute average demand level? If not, what does it represent?

f) Are the Company's demand allocators in the CCOSS for the E-32 L tariff based on the actual demand, or the ratcheted demand?

g) Are the Company's billing determinants in the Proof of Revenue workpaper based on the actual demand, or the ratcheted demand?

h) The tariffs state that the Company will place customers on the various E-32 scheduled "based on their average summer monthly maximum demand as determined by the Company each year." When do the tariff changes take place for customers? What measure of monthly maximum demand (15-minute, 1 hour, or something else) is used for these calculations?

i) How many customers are currently taking service on the E-32 L SP tariff? How many kW of energy storage do these

SEIA 26.2 (continued):

customers have?

j) Do customers that take service on the E-32 L tariff use different meters than customers that take service through the E-32 M tariff?

k) If a customer is switched from the E-32 M tariff to the E-32 L tariff based on its demand, does the Company switch the meter?

l) If a customer is switched from the E-32 L tariff to the E-32 M tariff based on its demand, does the Company switch the meter?

m) What contributes to the sizable metering cost difference between the E-32 M and E-32 L tariffs?

Response:

a) The tiered demand charges for unbundled delivery service reflect that some of the costs recovered through the demand charge are the type of fixed costs that could be justified to be recovered through a monthly service charge or otherwise have a higher unit cost of service for smaller customers in the rate class. The tiered load-factor-based energy charges for unbundled generation service in rates E-32 S and E-32 M has an implicit demand component in the first tier. This design is used instead of a non-tiered energy charge and a demand charge.

b) Please see the Company's response to part a.

c) It is a reasonable level to reflect the cost-based issues discussed in the Company's response to part a.

d) Yes.

e) Yes.

f) Please refer to the Company's response to SEIA 25.2, part b.

g) Please refer to the Company's response to SEIA 25.2, part c.

h) The rate change takes place in the January billing cycle and is based on 15-minute metered demand.

Response to SEIA 26.2 (continued):

i) None.

j) Rates E-32 M and E-32 L customers have similar options for metering equipment, which are based on the customer's electrical service requirements. However, the E-32 L customers require more expensive metering equipment on average due to their higher loads and service voltages.

k) No, unless new metering equipment is needed to support a change in the customers service requirements.

l) No, unless new metering equipment is needed to support a change in the customers service requirements.

m) Please refer to the Company's response to part j.

Witness: Leland Snook

Attachment KL-47, SEIA 27.1.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
TWENTY SEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 22, 2020

SEIA 27.1: Please refer to the Company's E-32 L tariffs.

a) Why does the Company propose to remove the E-32 L SP tariff from the LFCR?

b) Was the E-32 L SP tariff designed to be revenue neutral with respect to the E-32 L tariff? With the E-32 L TOU tariff? If not, please explain how the revenue recovery of the rate was designed.

c) In simulating the impact of the E-32 L, E-32 L TOU, and E-32 L SP tariffs against DOE commercial building hourly data, it appears that the E-32 L SP tariff produces a substantially higher (~50-60%) annual bill than either the E-32 L and E-32 L TOU rate for a customer without solar or storage. This change appears to be driven from the high demand charges of this tariff relative to the other tariffs. Is this an expected result? If so, please explain.

d) Please provide all analyses that the Company has performed related to the revenue-neutrality of the E-32 L SP tariff.

Response:

a) The Company proposes to exempt rate E-32 L SP from the LFCR surcharge to be consistent with rates E-32 L and E-32 TOU L, which are also exempt.

b) No. The class-wide revenue neutrality concept is not appropriate for specialty rates like E-32 L SP, because only a limited number of customers are likely to be eligible for, or participate in, the rate. The rate design was proposed by solar/storage parties in the last rate case and patterned after a similar rate for Tucson Electric Power. The final negotiated charges appeared to the Company to reasonably reflect cost of service.

c) The Company has not conducted a similar building simulation study and therefore cannot attest to the merits or validity of SEIA's purported findings. The E-32 L SP rate is designed for a customer that can significantly reduce their billing demand through energy storage. The rate has higher demand charges compared with rates E-32 L and E-32 TOU L, but also has significantly lower energy charges. In addition, the E-32 L SP rate does not have tiered demand

Witness: Leland Snook

Response to SEIA 27.1 (continued):

charges or monthly demand ratchet adjustments – issues that were important to solar parties in the last rate case.

d) Please refer to the Company's response to part b.

Witness: Leland Snook

Attachment KL-48, SEIA 27.2.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
TWENTY SEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 22, 2020

SEIA 27.2: Please refer to the Company's E-32 L SP tariff. For each customer taking service on this tariff, please provide the following information. Please note this is not requesting personally identifiable information.

a) Monthly on-peak, remainder, and off-peak demand.

b) Monthly on-peak, remainder, and off-peak kWh.

c) Energy storage capacity in kWAC and kWh.

d) If installed, solar system capacity in kWAC and kWDC.

e) If installed, whether the solar and storage systems are AC or DC coupled.

Response: There are no customers on E-32 L SP.

Witness: Leland Snook